Gas Decarbonization and Energy System Integration

– Situation in Europe and Implications for Japan –

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Summary

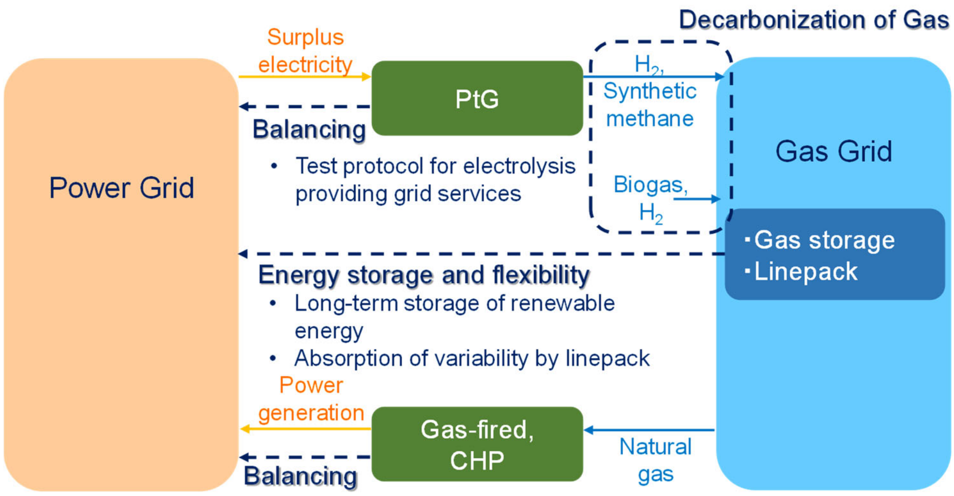
This report presents an overview of efforts underway in Europe toward gas decarbonization and energy system integration (sector coupling) and describes the challenges and possibilities of these measures through comparison with the efforts and discussions underway in Japan.

Europe and Japan have major differences in their networks and regulatory systems, but are also similar in that both have scarce resources of biogas and their options for gas decarbonization are limited to hydrogen and hydrogen-sourced carbon neutral (CN) methane. The challenge for both parties boil down to one issue: how to obtain hydrogen and CN methane and inject them into the gas network. Europe is planning to increase the hydrogen blending ratio in existing gas networks in stages, with a view to repurposing the gas networks for 100% hydrogen and building new hydrogen infrastructure in the process. Meanwhile, Japan's main approach is to blend CN methane into city gas, and has set a policy course of reducing the standard CV to 40 MJ/m^3, close to that of methane.

Gas decarbonization requires significant amounts of hydrogen and CN methane, which Japan may need to purchase from other countries. However, it is also important to pursue the concept of energy system integration, in which the gas network, inclusive of Power to Gas (PtG) and cogeneration, is used to address output fluctuations associated with the mass introduction of domestic VRE to build a decarbonized society, while also decarbonizing the gas itself by including VRE in the process. This is because existing electric power networks alone will not be able to cope with the enormous amounts of VRE that will need to be introduced. New measures such as strengthening inter-regional transmission lines and battery cells will be necessary but these may not be sufficient. Meanwhile, existing gas networks are already equipped with an energy storage capability and flexibility owing to the physical characteristics of the gas; incorporating Power to Gas into the networks will allow these functions to be used to mitigate VRE output fluctuations. In other words, the gas network is inherently highly compatible with VRE. Needless to say, it will be necessary to evaluate and determine what kinds of measures will be economically efficient for dealing with the mass introduction of VRE, but based on the above, utilizing well-established existing gas networks is an option worth considering. Europe is making progress with discussions on energy system integration, and has begun specific discussions on revisiting the definition of energy storage technology and on providing grid balancing capability using water electrolysis. Thus, Europe is addressing gas decarbonization and energy system integration as an integrated whole, as shown in the figure below.

Energy system integration is also valuable from the perspective of resilience. From the efficiency perspective, it is preferable to use VRE-sourced hydrogen from PtG and CN methane for producing heat. However, by using water electrolysis and CHP to ease VRE output fluctuations and stored hydrogen and CN methane for emergencies, the overall resilience of the energy system will be enhanced. In this case, it may be possible to further optimize energy system operations if electricity and gas networks can be operated in a coordinated manner.

Meanwhile, as energy system integration involves both electricity and gas, various regulation-related issues must be resolved to achieve it, such as the definition of energy storage and the use of grid balancing capacity. Before this can be done, it is necessary to determine how much flexibility the entire gas network has, including gas holders and the line pack of pipelines.



Decarbonization of Gas and Energy System Integration in Europe

Introduction

Efforts to build a decarbonized economy by 2050 are accelerating in and outside Japan. While electricity is being decarbonized mainly by introducing renewable energy, the only technology for decarbonizing gas with a long experience so far is biogas, but the amount is limited. In Japan, discussions on gas decarbonization gained momentum in FY2020[1] and the gas industry is seeing the declaration of a series of carbon neutrality goals. The most promising decarbonization options are hydrogen and hydrogen-based synthetic methane (carbon neutral (CN) methane), with particularly high expectations for CN methane, as demonstrated by the launch of a "Public-private Council for Promoting Methanation". This is because CN methane, produced from hydrogen and CO_2, facilitates the use of hydrogen in the existing infrastructure for city gas, whose main component is methane; the CO_2 re-emitted when burning CN methane is offset with the CO_2 that has been sequestrated, and thus using CN methane is synonymous with using hydrogen[2].

Europe is also accelerating efforts toward gas decarbonization. Europe, like Japan, positions hydrogen and CN methane as key fuels, but characteristically places higher emphasis on hydrogen. Further, along with gas decarbonization, Europe is accelerating efforts toward Energy System Integration, aiming to decarbonize the entire energy system by incorporating variable renewable energy (VRE) effectively into the gas network. This is done by using the functions as energy storage and flexibility inherently equipped with the existing gas network infrastructure.

This report outlines the efforts toward gas decarbonization in Europe in Chapter 1. Chapter 2 maps out the correlation between Japan's calorific value regulation for gas and its gas decarbonization efforts. Chapter 3 examines Europe's efforts toward energy system integration, focusing on the role of gas networks. Based on the above, Chapter 4 presents implications to the role that the gas industry can play in Japan's decarbonization efforts.

1. Overview of Europe's Efforts toward Gas Decarbonization

Amid growing expectations for CN methane, which can be used in existing city gas infrastructure, as a means of gas decarbonization, Europe is also working on blending more hydrogen into its city gas infrastructure. Why is Europe pursuing hydrogen blending when it is clear—based on the composition of city gas—that CN methane is more suitable than hydrogen? To understand the objectives and the background of this move, the following sections discuss Europe's efforts on the blending of hydrogen and CN methane into city gas currently underway, referring to documents released by the European Commission and Europe's gas industry.

[1] Study Group on the Future of the Gas Business toward 2050, Ministry of Economy, Trade and Industry.
[2] Shibata, Otsuki, "*Essay on sources of carbon in recycled carbon fuels (1) – (4)*," IEEJ, May 2021.

1.1. Hydrogen blending

1.1.1. European Commission

(1) "Hydrogen Strategy"

Europe is working on the wider adoption of green hydrogen generated primarily from solar PV and wind power as one of the initiatives to achieve its 2050 carbon neutrality target. In July 2020, it released "A hydrogen strategy for a climate-neutral Europe", setting a roadmap for introducing electrolyzers for producing hydrogen and upgrading infrastructure to increase hydrogen to 13–14% of the EU's energy mix by 2050.[3] The strategy stresses that the large-scale, rapid spread of green hydrogen use would lead to the EU reducing its GHG emissions by 50–55% by 2030 in a cost-efficient way.

Based on this strategy, blending limited percentages of hydrogen into the existing natural gas network is considered to be an efficient way of using green hydrogen in the local network during the transition period. However, the strategy also expresses the concern that blending changes the quality of the gas and may affect the design of gas infrastructure, end-user applications, and cross-border system interoperability. It goes on to point out that blending risks fragmenting the internal market if neighboring member states accept different levels of blending and cross-border flows are hindered.

To mitigate this possibility, the technical feasibility of adjusting the quality and cost of handling the differences in gas quality need to be assessed.[4] Moreover, reinforcement of instruments may be needed to secure cross-border coordination and system interoperability to avoid impeding the flow of gas across member states.

(2) "Strategy for Energy System Integration"

On the same day as the hydrogen strategy, the European Commission released "An EU Strategy for Energy System Integration". This strategy charts a path towards decarbonization across all sectors of the EU. In addition to decarbonization efforts in the electricity, gas, heat, and transport sectors, its key objective is energy system integration, through which the entire energy system is decarbonized by integrating electricity with other sectors and utilizing renewable energy among them.

The Strategy also points out that green hydrogen will allow the integration of large amounts of VRE in sectors such as maritime transport, heavy-duty road and rail transport, steel, oil refining, and chemicals, where decarbonization by electrification is currently difficult technically. Since even a fully integrated energy system cannot completely eliminate CO_2 emissions from all parts of the economy, the strategy stresses the importance of utilizing carbon capture and storage (CCS), as well as the need to use synthetic fuels, produced by combining CO_2 and green hydrogen, in hard-to-decarbonize sectors.

For hydrogen blending, the strategy suggests that a blend of 5–20% by volume can be tolerated by

[3] See European Commission, "A hydrogen strategy for a climate-neutral Europe," COM(2020)301 final.
[4] *Ibid.*

most systems without the need for major infrastructure upgrades or other measures. However, the possible need for dedicated infrastructure for large-scale storage and transportation of pure hydrogen is also mentioned.

1.1.2. European gas industry

(1) Initiatives and scenarios for gas sector decarbonization

In April 2020, 10 gas companies and two biomethane associations from eight European countries including Italy, Belgium, Germany, and the Netherlands launched the European Hydrogen Backbone initiative, and released “Gas Decarbonisation Pathways 2020-2050”, a report setting out the initiatives and pathways for decarbonizing the gas sector by 2050.[5]

The report points out that the policies outlined in the Clean Energy Package released by the European Commission in November 2016 and the European Green Deal in December 2019 are not sufficient and do not provide incentives for pursuing timely and cost-efficient decarbonization in the gas sector, and proposed four policy recommendations for more rapid decarbonization of the sector.[6] First, adopt the EU regulatory framework to make gas infrastructure future-proof in an integrated energy system. Second, stimulate the production of biomethane and hydrogen by a binding mandate for 10% gas from renewable sources by 2030. Third, foster cross-border trade of hydrogen and biomethane by a Guarantee of Origin system, and clarify market rules for green and blue hydrogen including for hydrogen transport. Fourth, incentivize demand for hydrogen and biomethane by strengthening the EU Emissions Trading System (ETS) combined with targeted and time-bound Contracts for Difference.

The “Accelerated Decarbonisation Pathway”, released in tandem with these initiatives, forecasts the 2050 supply and demand of gas to be as shown in Figure 1-1. According to this scenario, between 2020 and 2030, the total gas demand will decrease as energy efficiency improves and electrification expands, while the share of renewable gases including biomethane will increase by around 10%. From 2030, gas supply will increase slightly as more blue hydrogen (fossil fuels + CCS) and synthetic fuels are produced, but gas demand will decrease again between 2040 and 2050, and total gas demand will be covered by renewable gas or low-carbon gas from 2050. Notably in this scenario, the natural gas supply is expected to tend to decline while green hydrogen will grow significantly in 2030 and beyond.

Under this scenario, which anticipates the growth of green hydrogen, hydrogen blending is considered to be an effective temporary solution for boosting hydrogen production and facilitating CO_2 emission reductions during the 2020s. A blend of 5–20% is considered to be technically feasible with minimal investment using existing gas networks. However, the actual feasibility of blending

[5] Parties involved in creating this report: 10 gas companies namely Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, ONTRAS, OGE, Snam, Swedegas, and Teréga, and two biomethane associations namely EBA and Consorzio Italiano Biogas.

[6] Gas for Climate, “Gas Decarbonisation Pathways 2020-2050,” April 2020, p.II.

depends on the hydrogen tolerance of individual end-user appliances, based on the combustion characteristics of the blends. The scenario suggests that to move to higher blending percentages, changes need to be made to end-user appliances (such as burners) as well as the existing gas networks. While these points need to be considered, using green hydrogen locally and regionally by blending in gas distribution grids may be an effective temporary solution between 2020 and 2030.

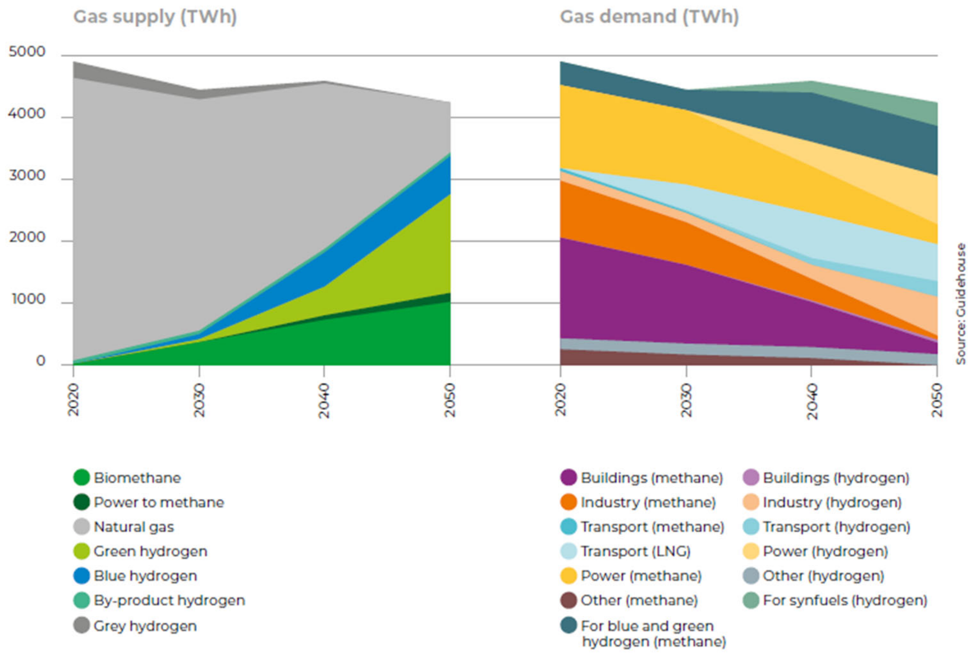


Figure 1-1 Forecast for gas supply (left) and demand (right) (Accelerated Decarbonisation Pathway scenario)
Source: excerpted from Gas for Climate, "Gas Decarbonisation Pathways 2020-2050," April 2020, p.11

(2) Infrastructure upgrade for hydrogen blending

The existing gas infrastructure is not sufficient for supporting the amount of hydrogen considered necessary for achieving carbon neutrality by 2050. First, dedicated hydrogen infrastructure needs to be built on a member state and regional level, and then on a Europe-wide level in the future.[7] Under the vision of the European Network of Transmission System Operators for Gas (ETNSO-G), a regulatory framework for this purpose will be established by 2024, the regions with particular demand for hydrogen will be identified and a network connecting those regions will start to be built by 2030, and EU-wide hydrogen infrastructure will be put in place by 2050. This pan-EU hydrogen infrastructure is planned to be 22,900 km in total length, with 75% coming from improving existing infrastructure and the remaining 25% by laying new hydrogen pipelines.[8]

[7] Gas for Climate (2020), *op.cit.*
[8] Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Snam, Swedegas, Teréga, "European Hydrogen Backbone," July 2020.

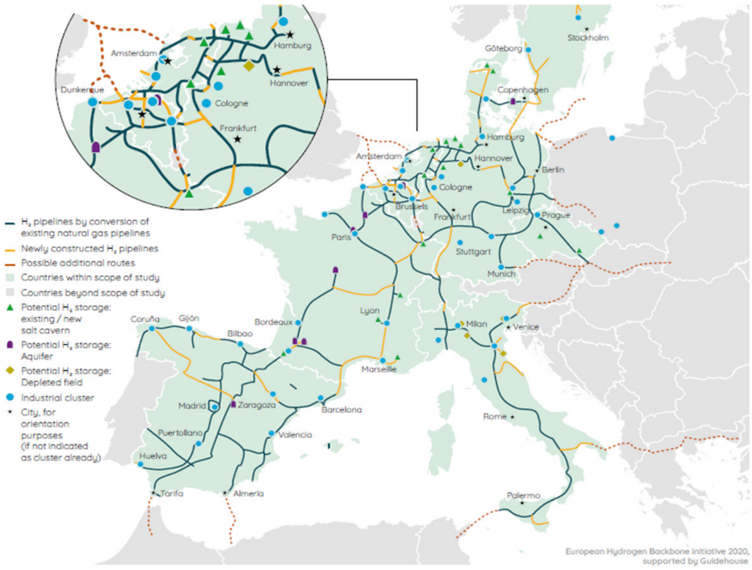


Figure 1-2　Hydrogen pipelines envisaged for 2040

Source: Excerpted from Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Snam, Swedegas, Teréga, "European Hydrogen Backbone," July 2020, p.8

According to "ENTSOG 2050 Roadmap: Action Plan" published by ENTSO-G in October 2020, dedicated hydrogen infrastructure will be developed under the framework of the Ten-Year Network Development Plans (TYNDPs), which are being formulated at both the member state and EU levels.[9] The development will take into consideration interlinkage with the electricity sector, in line with the European Commission's EU Strategy for Energy System Integration. On the agenda of ENTSO-G's Action Plan is digitalized system design for the smooth handling of gas quality, to identify localized consumer needs for blending and aligning uses across the EU.

1.1.3. Major European countries

Let's now turn to major European countries. While many countries limit hydrogen blending in natural gas networks to 2%, some countries allow higher percentages, namely Germany with up to 10% (provided that no CNG charging stations are connected to the infrastructure), France 6%, Spain 5%, and Austria 4%[10]. The following sections outline the hydrogen blending efforts in Germany and France, which allow particularly high blending percentages.

(1) Status of hydrogen blending in Germany

In Germany, where there are still no domestic laws or regulations on hydrogen blending in natural gas networks, the percentage of hydrogen that can be blended is determined based on a test of the performance of major equipment in the gas transmission, distribution, storage, and end-user legs.

[9] ENTSOG, "2050 Roadmap: Action Plan."
[10] See IEA, "The future of Hydrogen: Seizing today's opportunities," June 2019, p.73.

Specifically, percentages of up to 2% are allowed for systems that have CNG charger stations connected, up to 0.2% for those without calibrated hydrogen measurement systems installed, and up to 10% for others.[11] According to German gas company MARCOGAZ, the allowable level of hydrogen blending in gas networks must be verified case-by-case and also depends on the quality of natural gas and licensing by the municipalities concerned.[12]

In Germany, which is the global frontrunner of Power to Gas (PtG) with many companies conducting PtG demonstration experiments, the installed capacity of electrolyzers has increased to nearly 600 MW according to the PtG plans released up to the end of 2019. In June 2020, the German government formulated the National Hydrogen Strategy and announced plans to expand the electrolyzer capacity to 5 GW and supply 350,000 tonnes (14 TWh) of green hydrogen by 2030. It has also set the target of increasing the electrolyzer capacity to 10 GW by 2040.

Under these targets, one of the hydrogen production demonstration projects in full swing is the Reallabor Westküste 100 project.[13] This project is demonstrating hydrogen production using the renewable electricity produced by offshore wind plants off the west coast of Schleswig-Holstein, the northernmost state of Germany, to reduce carbon emissions from the industrial and transport sectors, as well as the storage of hydrogen. Ten companies including Stadtwerke Heide (public corporation for electricity, gas, water, and heat), EDF Deutschland (energy company), OGE (electricity transmission company), Ørsted Deutschland (wind power operator), and Raffinerie Heide (petroleum refiner) have formed a cross-sector partnership and are participating in the project, to create a new cycle of resources across different industries using existing industrial infrastructure in the state. The project is scheduled to install 30 MW of electrolyzers within five years from the start of the project, and following operational and maintenance tests, expand it to up to 700 MW in the future. The green hydrogen produced in this project will be sent via a dedicated hydrogen pipeline to Heide public company, where it will be injected into the natural gas network. Blending of up to 20% is considered possible, and the goal is to supply 100% hydrogen by 2050.

(2) Status of hydrogen blending in France

In France, nine gas companies jointly analyzed the technical and economic requirements for hydrogen blending based on the government's hydrogen deployment plan for energy transition formulated in June 2018, and released a report titled "Technical and Economic Conditions for Injecting Hydrogen into Natural Gas Networks" in June 2019. The report states that while case-by-case verifications are necessary, up to 6% of hydrogen can be injected into the networks based on the current gas-related equipment specifications. Hydrogen blending of up to 10% is expected to be

[11] MARCOGAZ, "ENTSO-G Workshop on Principles for EU Gas Quality, Handling of Hydrogen and CO2 Transportation" 29 April 2020.
[12] *Ibid.*
[13] For Reallabor Westküste 100 project, see Westküste 100 website (https://www.westkueste100.de/en/).

possible by 2030 with the progress in equipment performance as well as in research and development, but injecting 20% or higher would require significant investments and therefore any decision must be carefully considered in view of its rationality.[14]

The French government announced its national hydrogen strategy in September 2020 and has set the goal of installing 6.5 GW of electrolyzers and producing 600,000 tonnes of green hydrogen a year by 2030. Regional municipalities are also actively engaged in deploying hydrogen. For example, the Jupiter 1000 project, in which hydrogen is produced using solar PV and wind power, is being conducted in Fos-sur-mer, a community in the Provence-Alpes-Côte d'Azur region in southern France.[15] The project is attracting attention both in and outside the country as the first demonstration project that connects with France's live gas networks. A consortium of nine companies including GRTgaz (gas company), Rte (transmission system operator), and CNZ (renewable electricity producer) are involved in the project and conducting demonstration experiments using two different types of electrolysis systems (both 0.5 MW): one produces renewable hydrogen and injects it directly into the gas network, while the other converts the produced renewable hydrogen into CN methane by methanation before injecting it into the network. For both methods, a section of the natural gas pipeline was diverted and connected to the electrolyzers, and it was possible to inject hydrogen and CN methane into it.

1.2. CN methane blending

CN methane can be injected into the existing natural gas infrastructure without any major barriers. Therefore, expectations are rising for the technology as a means to decarbonize city gas without incurring additional costs such as for precise verification of the required blending ratio and compatibility with equipment, or for preparation of new infrastructure, unlike hydrogen. However, it is a very expensive option because of the enormous costs required, particularly for supplying CO_2 and installing methanation equipment, posing a major challenge.[16]

Furthermore, the European Commission has pointed out that for synthetic methane to be recognized as completely carbon neutral methane (CN methane), the CO_2 must be sourced from biomass or the atmosphere.[17] The Commission has also stated that it is important to accurately measure the amount of carbon emitted during the production of synthetic methane by employing a system for appropriately monitoring and reporting the CO_2 emissions.[18] It also stresses the importance of creating incentives

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[14] See GRTgaz, GRDF, Teréga, Storengy France, Géométhane, Elengy, Réseau GDS, Régaz-Bordeaux, SPEGNN, "Technical and economic conditions for injecting hydrogen into natural gas networks" June 2019.

[15] For Jupiter 1000 project, see Jupiter 1000 project website (https://www.jupiter1000.eu/single-post/2017/11/14/ladaptation-du-r%C3%A9seau-en-action).

[16] See IRENA, "Hydrogen: A renewable energy perspective," September 2019.

[17] See November 2018, "Vision for a long-term EU strategy for reducing greenhouse gas emissions" and July 2020 "Energy System Integration Strategy."

[18] See European Commission, "Powering a climate-neutral economy: An EU Strategy for Energy System Integration," COM(2020)299 final.

for including synthetic fuels in the market by introducing the carbon removal certification mechanism, a mechanism to guarantee the traceability of CO_2 advocated by the Circular Economy Action Plan.[19]

As described above, Europe tends to require decarbonization of not only synthetic methane itself but also the CO_2 used to produce it. This makes it necessary to consider the carbon intensity of the entire value chain, including the origin of the CO_2, when using synthetic methane. Nevertheless, there are high expectations for synthetic methane as the fuel is synthesized from renewable hydrogen and CO_2 and can be used for hard-to-decarbonize sectors, such as ships, railway, chemicals, steel, and oil refining, thereby widening the range of sectors that can be decarbonized, as well as having further scope for cost reduction. Based on such expectations, an EU gas industry report[20] predicts that synthetic methane produced from carbon-neutral hydrogen will be adopted widely in 2030–2050, and will be injected into the gas networks from 2040 as its production increases.

1.3. Wrap-up of gas decarbonization in Europe

As described above, in Europe, there are rising expectations for CN methane, which can be used in existing city gas infrastructure, as a means for decarbonizing city gas. Meanwhile, efforts are also underway to increase hydrogen blending in the city's gas infrastructure. Europe currently considers that hydrogen blending of 5–20% is possible without incurring additional investment costs or infrastructure development, and is therefore effective for expanding hydrogen supply to a certain level. Various efforts are already underway in Germany, France, and other countries. Meanwhile, some of the challenges of hydrogen blending include the decrease in energy intensity of the resulting gas mixture and possible adverse effects on facility operations and products caused by fluctuations in blending ratios.

Despite the current limitations on the blending ratio, the reason why Europe is proceeding with hydrogen blending is that it is seen as a useful and efficient way of deploying large amounts of green hydrogen and integrating it into the energy system in the early phase (the 2020s) as they work to accelerate the use of green hydrogen aiming to reach carbon neutrality by 2050. Hydrogen blending is also considered effective for creating an additional role for the gas sector in reaching carbon neutrality, helping to prevent existing gas infrastructure from becoming stranded assets as natural gas demand is expected to decline in the future.

Key points for increasing hydrogen blending going forward include dealing with differences in gas quality, cost adjustment, formulating initiatives for reducing the risk of investments necessary for expanding blending, adjusting the different blending ratio regulations among countries, and securing cross-border system interoperability. To back these efforts, a framework for incentivizing

[19] *Ibid.*
[20] See Gas for Climate, "Gas Decarbonisation Pathways 2020-2050," April 2020, p.40.

gas companies to use green hydrogen will need to be set up. For CN methane, it is also necessary to conduct demonstration projects to support technological development and thereby reduce costs.

2. Japan's Calorific Value Regulation for Gas and Its Relevance to Gas Decarbonization

As with Europe, decarbonization of gas is a challenge for Japan as the country strives to reach carbon neutrality by 2050. The Study Group on the Future of the Gas Business toward 2050[21] established by the Ministry of Economy, Trade and Industry (METI) in FY2020 has clarified the role of gas and the efforts required, including enhancing resilience and the business base, as well as decarbonization. For decarbonization, the importance of methanation and hydrogen was emphasized. Accordingly, METI launched the Public-private Council to Promote Methanation in June 2021, and public-private efforts for solving technical, economic, and institutional challenges centered on methanation have just started.

Meanwhile, the Working Group to Study the Gas Business ("the Gas Business WG") launched in 2018 (under the Basic Policy Subcommittee on Electricity and Gas of the Electricity and Gas Industry Committee, Advisory Committee for Natural Resources and Energy) has been considering system reforms to create a more competitive gas market based on the outcome of the full-scale liberalization of the gas retail business in April 2017, and the calorific value (CV) regulation for gas was part of the scope.

This chapter examines the relationship between Japan's gas CV regulation and the moves toward gas decarbonization.

2.1. Overview of discussions on the CV regulation

(1) Background to the discussions

Japan's city gas is supplied under the "standard CV regulation," which sets a standard CV per unit volume of gas (the minimum monthly arithmetic mean) and limits fluctuations in the CV for the gas supplied. The standard CV regulation ensures that the gas supply has a certain CV, thereby ensuring the safety and efficiency of combustion appliances and user benefits such as fair fees, which in turn has helped expand and enhance the use of gas. As the CVs of LNG imported to Japan vary depending on its origin, the CV must be adjusted to meet the standard CV by mixing LPG into LNG in a CV adjustment plant during production. Gas companies that do not have such plants must either obtain one or outsource gas production to other companies, raising, as some point out, an entry barrier for the gas retail business.

Meanwhile, as the global carbon neutrality movement accelerates, there is growing attention on the injection of CN methane and hydrogen into gas pipelines as a way of decarbonizing city gas. As these

[21] https://www.meti.go.jp/shingikai/energy_environment/2050_gas_jigyo/index.html.

gases have smaller CVs than city gas, the Gas Business WG has been considering revising the current CV regulation. The following section outlines the discussions at the Gas Business WG and summarizes the possibility of blending CN methane and hydrogen (injection into gas pipelines).

The recent discussions on the CV regulation commenced with the launch of the Gas Business WG (September 2018), as one of the challenges in spurring competition through the full liberalization of the gas retail business. The decision was made to conduct reviews based on the following:

1) A study on the possible impact of the transition to the band-based CV regulation on the safety and performance of gas equipment, and the measures to be taken for combustion equipment that will be affected
2) A survey on the actual situation of the band-based CV regulation in other countries

Thereafter, the impact of CV fluctuations was studied for a wide range of gas equipment including gas engines, industrial furnaces, air conditioners, household and commercial-grade burners, and fuel cells. The results are shown in Table 2-1.

Table 2-1 Impact of CV fluctuations on gas equipment

			Performance			Safety			Product Quality ＊1		
			43-45MJ/m^3	42-46MJ/m^3	40-46MJ/m^3	43-45MJ/m^3	42-46MJ/m^3	40-46MJ/m^3	43-45MJ/m^3	42-46MJ/m^3	40-46MJ/m^3
			±2%	±5%	±7%	±2%	±5%	±7%	±2%	±5%	±7%
Gas engine [200-9000kW]			▲	×	×	▲	×	×	▲	×	×
Industrial Furnace	Industrial Furnace (General)	Industrial combustion furnace (general)	▲	▲	▲	▲	▲	▲	▲	▲	▲
		Steel/Cupper heating furnace/RT burne	▲	▲	▲	▲	▲	▲	▲	▲	▲
		Ceramic heating furnace ＊2	▲	▲	▲	▲	▲	×	▲	▲	×
	Atmospheric gas generator		▲	▲	▲	▲	▲	▲	▲	×	×
	Glass melting furnace		×	×	×	×	×	×	×	×	×
Air conditioner		Absorption chiller/heater	×	×	×	▲	×	×	×	×	×
		GHP	▲	×	×	▲	×	×	▲	×	×
Commercial combustion equipment		Range	▲	▲	×	○＊3	○＊3	▲	▲	▲	×
		Rice cooker	▲	▲	××	○＊3	○＊3	○＊3	▲	×	××
		Continuous Rice Cooker	▲	×	×	○＊3	○＊3	○＊3	▲	×	×
		Noodle boiler	▲	▲	×	○＊3	○＊3	○＊3	▲	▲	×
		Steam convection oven	▲	▲	×	○＊3	○＊3	○＊3	▲	▲	×
		Small pottery furnace	▲	▲	×	○＊3	○＊3	○＊3	▲	▲	×
		Large continuous pottery furnace	▲	▲	×	○＊3	○＊3	○＊3	▲	×	×
Residential combustion equipment		Stove	○	▲	××	○	○	▲	○	▲	××
		Rice cooker/ Gas oven	○	○	▲	○	○	○	○	○	▲
		Water heater	○	▲	××	○	▲	××	○	▲	××
		Gas air condition	○	▲	×	○	○	○	○	▲	×
		Clothes dryer	○	▲	×	○	○	○	○	▲	×
Fuel cell		Residential/Commercial/Industrial	▲	××	××	○＊4	○＊4	○＊4	▲	××	××
		○：No impact ▲：Possible impact ×：Impact (Hearing results) ××：Impact (Actual device verification results)									

＊1: For industrial furnaces and commercial combustion equipment, products manufactured using the relevant products. For air conditioners, etc., the air to be controlled.
＊2: Except for glass furnaces
＊3: Only equipment that has been developed to comply with standards such as JIS S2103, which is a standard for household use, such as products certified by a third party.
＊4: The system is designed to automatically shut down before it reaches an unsafe state, so it was rated "no impact". (Operation cannot be continued and the original function cannot be performed.)
＊5: The gas appliances listed in the table are examples of major combustion appliances that are considered to have a significant impact on safety and performance, and do not cover all gas appliances used in Japan.
＊6: The ratings represent the majority of ratings for each device, and some devices may have different ratings.
Source: Report on the impact of the band-based CV regulation on equipment (December 25, 2019, Agency for Natural Resources and Energy), p.5

An interim report issued subsequently (at the 13th Gas Business WG on July 10, 2020) concluded as follows: “The impact of the transition to the band-based CV regulation on combustion equipment was studied and necessary modification costs were estimated. A comparison between options, namely a lower standard CV and four CV bands of different widths, indicated that wider bands cause greater increases in costs compared to their effects.”

The actual situation of the band-based CV regulation has been studied in South Korea, Europe, and the United States, focusing on the charging method and installation of calorimeters. The interim report stated that: “The survey of the situation in various countries indicated that there is a difference in natural gas procurement method and the status of gas networks between Japan and Europe, which adopts the band-based CV regulation, and that measures are also being taken in Europe to ensure a stable CV for some consumers.”

Thereafter, the charging method, the issue of who will bear the modification costs, and the timeline leading up to implementation were studied for three options: reduction of the current standard CV (44 MJ/m^3, etc.) and the narrower bandwidths of 44–46 MJ/m^3 and 43–45 MJ/m^3. As shown in Table 2-2, the modification costs were at least 10 times higher for the band-based CV than the reduction of standard CV. Also, setting a transition period of at least 20 years, rather than 10 years, was shown to significantly decrease the modification costs for appliances.

Table 2-2 Effects and necessary costs

(reduction of standard CV: 44 MJ/m^3, CV bands: 44–46 MJ/m^3, 43–45 MJ/m^3)

			Befor transition					After transition					
			Initial cost					Effect [year]	Mainenance cost [year]				Total [year]
			Equipment countermeasure	Manufacturing facilities, etc.	Calorimeters, etc.	Publicity	Total	LPG cost reduction	Equipment	Heat reduction material	Calorimeters, etc.	Manufacturing facilities, etc.	
Time to transition: 10 years	Standard Heat Value	Reduction (4.4MJ/m3)	4,605 (2,880)	67	0	39	**4,711 (2,986)**	-17	0	0.027	0	9	**-8**
	Heat Band	4.4-4.6 MJ/m3	86,761 (84,511)	1,117	971	112	**88,961 (86,710)**	-17	38	0	42	166	**229**
		4.3-4.5 MJ/m3	86,758 (84,508)	1,229	971	112	**89,070 (86,819)**	-42	38	0.0013	42	177	**215**
Time to transition: 20 years	Standard Heat Value	Reduction (4.4MJ/m3)	104 (295)	67	0	39	**211 (401)**	-17	0	0.027	0	9	**-8**
	Heat Band	4.4-4.6 MJ/m3	5,139	1,117	971	112	**7,339**	-17	52	0	42	166	**243**
		4.3-4.5 MJ/m3	5,142	1,229	971	112	**7,454**	-42	52	0.0013	42	177	**229**
Time to transition: 30 years	Standard Heat Value	Reduction (4.4MJ/m3)	103 (295)	67	0	39	**209 (401)**	-17	0	0.027	0	9	**-8**
	Heat Band	4.4-4.6 MJ/m3	2,104	1,117	971	112	**4,304**	-17	57	0	42	166	**248**
		4.3-4.5 MJ/m3	2,108	1,229	971	112	**4,420**	-42	57	0.0013	42	177	**234**

＊: Due to rounding, the total value of each item does not match the value in the total column.

＊: In the case of standard heat value reduction and heat band (4.3-4.5MJ/m3), it may be necessary to install heat reduction equipment, but the cost of installation has not been recorded.

＊: No qualitative effects are recorded.

Source: Study on the band-based CV regulation (February 16, 2021, Agency for Natural Resources and Energy), p.14

(2) Conclusions of the study on the band-based CV regulation

In addition to the study above, in March 2021, the Gas Business WG issued its "Conclusions of the Study on the Calorific Value Band," [22] anticipating the injection of CN methane (with a CV of 40 MJ/m^3) into the city gas network, which is regarded as an effective gas decarbonization method. The key points are as follows.

- A reduced standard CV is more appropriate for the new CV regulation than the band-based CV regulation.
- The transition period should be 15–20 years.
- At this point, the rational option would be to reduce the standard CV to 40 MJ/m^3.
- The reduction of the standard CV shall be scheduled for 2045–2050. The most appropriate new CV regulation shall be finalized in 2030 after prior testing.

2.2. Discussion on the calorific value regulation and the decarbonization of gas

(1) Conclusions of the study on the band-based CV regulation

The discussions on the calorific value regulation concluded that the reduction of the standard CV should be adopted, rather than the band, with a transition period of 15–20 years, as a means to reduce and eliminate carbon emissions from city gas in the future using CN methane and to achieve CV transition at the lowest cost.

For electricity, there is essentially no difference between the electricity generated from renewable, nuclear and other zero-emission sources and that generated from fossil fuels, and mixing them to reduce carbon emissions causes no problem. The situation is quite different for gas: when supplying gas with different CVs and compositions, modifications at the user end will be essential.

City gas was initially produced by gasifying coal and petroleum, contained hydrogen and CO_2 as well as methane, and was supplied as a gas with a lower CV than the current one. It then became possible to import the current gas of mostly methane in the form of LNG and thus supply gas with a higher CV. This change of CV was carried out over several years by adjusting the appliances of each consumer one by one. A similar process will be necessary when changing the CV. Therefore, the Gas Business WG's conclusion that the shift to the final CV should be conducted in one step after carefully studying the necessary changes in equipment specifications is rational to make the shift economically.

(2) Possibility of supplying hydrogen (hydrogen blending) in Japan

[22] See URL for the conclusions of the study on the CV band by the Working Group to Study the Gas Business, Basic Policy Subcommittee on Electricity and Gas, Electricity and Gas Industry Committee, Advisory Committee for Natural Resources and Energy. https://www.meti.go.jp/shingikai/enecho/denryoku_gas/denryoku_gas/gas_jigyo_wg/20210407_report.html.

Efforts to utilize hydrogen are gaining momentum in Europe as described in Chapter 1, and discussions on hydrogen utilization and hydrogen blending are gathering momentum in Japan as well.

CN methane production involves both energy and costs for producing synthetic methane from hydrogen and CO_2, as well as for producing green hydrogen. In fact, there is no need to use CN methane if hydrogen can be used directly, but using hydrogen involves the following problems.

1) Developing and distributing hydrogen-ready equipment: The combustion characteristics of hydrogen differ significantly from the current city gas of mostly methane, and it is therefore essential to develop equipment that is compatible with hydrogen combustion. Turbines ready for the combustion of hydrogen and ammonia with conventional fuels and their eventual dedicated combustion are already being developed in the power sector, but to further spread the use of hydrogen, equipment that can burn hydrogen and policies to expand its use in non-power sectors are required.
2) Hydrogen supply (hydrogen blending): Before LNG was adopted in 1969, city gas contained hydrogen, and so it is considered that existing gas pipelines are capable of supplying gas containing a certain amount of hydrogen. However, as described earlier, changes in the CV and composition of gas will require adjustment of end-user appliances and therefore, raising the hydrogen content in stages is not considered realistic either from the safety or cost perspective. Meanwhile, supplying pure hydrogen would require the development and spread of equipment compatible with the gas, as described earlier, as well as designing pipelines that can avoid hydrogen embrittlement[23] and are fit for carrying gases with a smaller molecular weight. One possible reason why Europe is keener to supply hydrogen than Japan is the difference in the status of the pipeline network. Europe has a higher pipeline coverage ratio than Japan[24], which gives the region better access to lands suitable for renewable energies, the sources of green hydrogen.

As for the utilization and supply of CN methane through methanation, while it will be necessary to adjust gas appliances to cope with the change in CV, etc., the effort will be minor compared to developing and spreading hydrogen-ready appliances. Further, the supply itself is expected to require very little additional modification.

There is a regional hydrogen project currently underway in Fukushima prefecture. It is important to spread the use of hydrogen on a regional basis through projects such as this and to introduce more hydrogen in large facilities in the power and other sectors, in order to draw up a multi-path energy transition plan for decarbonizing gas.

[23] Embrittlement of metal resulting from absorption of hydrogen molecules by the metal.
[24] Committee to Study the Technical Challenges for Installing Gas Pipelines for the current situation of natural gas infrastructure and natural gas pipelines on highways (first), August 2016.

3. The Role of Gas Networks in the European Energy System Integration

In addition to the approaches toward decarbonizing gas summarized in Chapter 1, Europe is also working to utilize the inherent functions of the gas network to decarbonize the overall energy system. These efforts are based on concepts called Energy System Integration or Sector Coupling, in which gas networks are used as a source of the additional flexibility essential for the power grid to accommodate large amounts of variable renewable energy (VRE) as a means to decarbonize the energy system, while also decarbonizing the gas itself.

3.1. Increasing the flexibility of the energy system using the gas network

Energy system integration is the concept[25] of increasing the flexibility of the entire energy system by coupling the electricity network with other sectors and networks (sector coupling), thereby enabling the mass introduction of VRE. Among the various sectors and networks, the gas network, which is well-established,[26] is regarded as a promising candidate in Europe. There are various options for energy system integration, such as utilizing VRE in the transport sector in EVs and using VRE to meet the heat demand that has shifted from gas to electricity. However, Europe's gas network is expected to be a highly promising means for accepting VRE through PtG as its coverage is as broad and dense as the electricity network and it can also store energy, giving it sufficient flexibility.

(1) Accommodating VRE by the gas network

An increase in VRE capacity gives rise to excess VRE electricity that the grid cannot accept. This excess electricity could be used in the gas network by converting it into hydrogen or CN methane through PtG, which has been considered for some time. Japan, for example, has a relatively large demand for city gas of roughly half that for electricity[27], which makes the infrastructure highly promising for accepting hydrogen and CN methane sourced from VRE.

One study[28] indicated that the seasonal storage of VRE in the gas network through PtG would enhance flexibility. Another research[29] presented the possibility that VRE could be incorporated more efficiently into the energy system by the integrated operation of gas-fired power, which is increasingly in demand as a grid balancing capacity to cope with the growth of VRE capacity, with the electricity network, and utilizing the gas storage facilities of the gas network.

As suggested above, the source of the additional flexibility is the large gas demand itself and the

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[25] Shibata, "*Potential of Power to Gas in Japan*," IEEJ Energy Journal, Volume 42, Issue 1 (March 2016).
[26] IEA "World Energy Outlook" 2019.
[27] Shibata, "*Renewable energy storage using hydrogen*," The Japan Institute of Energy Journal "enerumikusu," 100, 161–167 (2021).
[28] Stephen Clegg, Pierluigi Mancarella, "Storing renewables in the gas network: modelling of power-to-gas seasonal storage flexibility in low-carbon power systems," IET Generation, Transmission & Distribution, 2016, Vol. 10, Iss. 3, pp. 566–575
[29] Hossein Ameli, Meysam Qadrdan, Goran Strbac, "Value of gas network infrastructure flexibility in supporting cost effective operation of power systems," Applied Energy 202 (2017) 571–580.

inherent energy storage capability of the gas network. In particular, the energy storage facilities of the gas network, which are typically underground storage facilities and gas holders such as depleted gas fields and salt caverns, exist in abundance in Europe[30]. These energy storage facilities can provide flexibility by absorbing VRE fluctuations of relatively long cycles.

(2) Flexibility provided by the linepack of gas pipelines

Another possible source of additional flexibility is the linepack of gas pipelines for relatively short cycle flexibility. The linepack is the volume of gas that mainly high-pressure gas pipelines[31] can hold or are holding[32]. In this report, the former is referred to as linepack capacity and the latter as linepack. As gas takes longer to travel from the supply location to the demand location than electricity, a certain amount of gas, or linepack, must be held inside the pipelines to respond to sudden fluctuations in gas demand. The higher the gas pressure, the larger the linepack capacity. The amount of linepack changes with time. The linepack capacity is charged (and the linepack increases) typically during nighttime when gas demand is low; the linepack starts to decrease as gas demand increases in the morning and daytime, creating a margin (buffer) in linepack capacity. By season, the buffer in linepack capacity is greater in wintertime when gas demand is high than during summertime. As the linepack capacity of a gas pipeline is designed to be able to respond to seasonal and time-of-day fluctuations in gas demand, it has flexibility to respond to fluctuations.

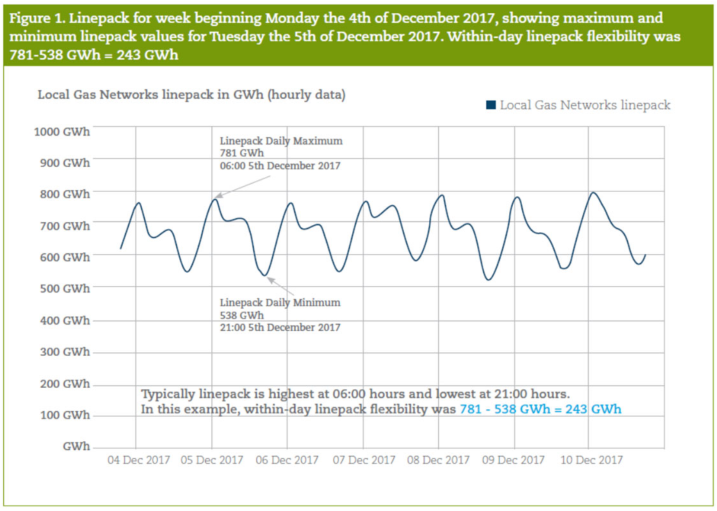

Figure 3-1 Change in linepack in Britain's gas distribution network (one-week sample from December)

Source: "Flexibility in Great Britain's gas networks: analysis of linepack and linepack flexibility using hourly data," UK Energy Research Centre, May 2019

[30] Shibata, "*Potential of Power to Gas in Japan*," IEEJ Energy Journal, Volume 42, Issue 1 (March 2016).

[31] "FLEXIBILITY IN THE ENERGY TRANSITION, A Toolbox for Gas DSOs", CEDEC, eurogas, GEOED, February 2018

[32] "Flexibility in Great Britain's gas networks: analysis of linepack and linepack flexibility using hourly data", UK Energy Research Centre, May 2019

Figure 3-1 presents the linepack in Britain's gas distribution network for one week in December based on hourly data. The linepack is charged to the maximum (reducing the linepack capacity to the minimum) every morning (around 6:00) to meet the day's gas demand, and declines to the lowest level at nighttime (around 21:00) when the day's highest space heating demand is reached (the linepack capacity reaching the day's highest level). The difference between the highest and lowest levels of linepack is used as the benchmark for the linepack flexibility of the gas pipeline.

The electric power system maintains a stable frequency and voltage by keeping the electricity supply and demand in balance on an hourly basis using the inertia and grid balancing capability provided by synchronous generators. While supply and demand match on an hourly basis, transmission lines have no such ability to keep supply and demand in balance.[33] Meanwhile, in a gas system, in which the supply and demand of gas are connected via pipelines that provide a buffer (i.e., the inertia of the gaseous material generated by a change in pressure or flow rate), supply (production and charge) and demand (discharge) are not in balance on an hourly basis[34] (Figure 3-2, Figure 3-3); when demand arises, the linepack inside the pipeline is pushed out first to reach the place of demand, rather than the gas supply source reacting immediately. There is no need to keep supply and demand in balance on an hourly basis, and a balance on a daily (within-day) basis would suffice.[35, 36] In other words, a gas pipeline is able to balance the supply and demand automatically; its ability to decouple fluctuations in demand from those of supply to a certain extent is one of its characteristics.

33 Note that synchronous stability becomes lower with longer transmission line connecting supply and demand.

34 The discussions on the full liberalization of gas retail conducted at Japan's Gas Systems Reform Subcommittee (ended in FY2016) considered reforms to the hourly balancing system of gas (which requires gas suppliers to keep the discrepancy between the charge and discharge of gas within 10% every hour). As a result, the load curve supply system, in which the gas charging patterns of new gas retailers are aligned with the charging pattern of the entire gas network concerned, was introduced. The "time-based balancing system" is a system concept; physically, the supply (production, charging) and demand (discharge) for gas are not in balance on an hourly basis (supply and balance match every hour).

35 "Flexibility in Great Britain's gas networks: analysis of linepack and linepack flexibility using hourly data," UK Energy Research Centre, May 2019.

36 "FLEXIBILITY IN THE ENERGY TRANSITION, A Toolbox for Gas DSOs," CEDEC, eurogas, GEOED, February 2018.

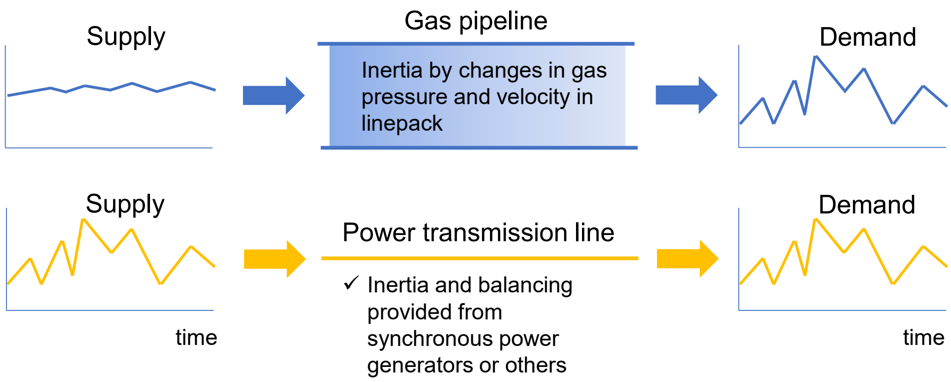

Figure 3-2 Difference in Balancing of Supply and Demand between Gas and Power Sector

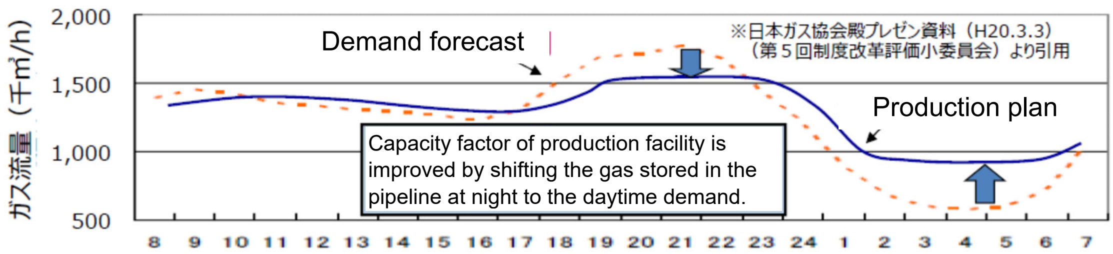

Figure 3-3 Sample of Hourly Profile of Gas Demand and Production in Japan

Source: 25th Gas Systems Reform Subcommittee meeting, Material 4, "*Detailed system design for the full-scale liberalization of retail business*," November 10, 2015

Figure 3-4 presents how linepack decouples the fluctuations in gas supply and gas demand. These are sample results from a simulation of gas consumption and gas supply patterns of gas-fired power, which will be required as a grid balancing capacity upon mass introduction of wind power (it is assumed that the gas network and the power network are connected via gas-fired power). "MISOCP" and "MILP" represent the optimum operation result with linepack considered; "No linepack" is the result without linepack. Whereas gas consumption and supply follow more or less the same for the "No linepack" case (see figure (f) in the bottom row), in "MISOCP" and "MILP," in which gas was charged and discharged as linepack (see figures (a) and (b) in the bottom row), we can see that gas supply remains more or less level while gas consumption fluctuates (see figures (d) and (e) in the bottom row).

The above analysis examined energy system integration between the gas and electricity networks by way of gas-fired power. However, it also indicates that gas pipelines have "inherent linepack flexibility of the (gas) grid"[37] that helps maintain the supply-demand balance. Some consider that

[37] Christopher J. Quarton, Sheila Samsatli, "Power-to-gas for injection into the gas grid: What can we learn from real-life projects, economic assessments and systems modelling?," Renewable and Sustainable Energy Reviews 98 (2018) 302–316.

linepack should be incorporated as a factor when evaluating energy system integration in which the gas produced by PtG is used in the gas network.[38]

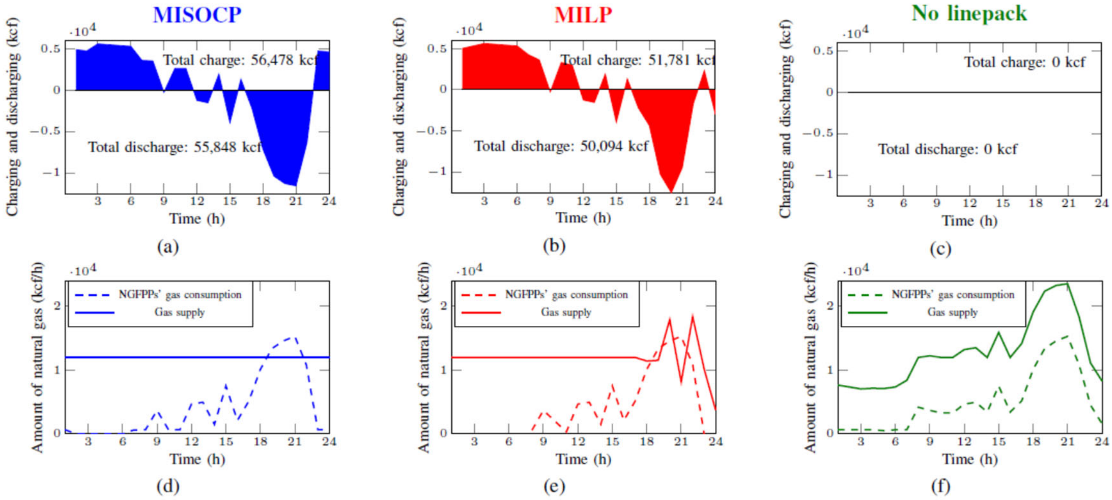

Figure 3-4 Gas consumption and supply patterns of balancing gas-fired power with and without linepack

Source: Schwele, Anna; Ordoudis, Christos; Kazempour, Jalal; Pinson, Pierre, "Coordination of Power and Natural Gas Systems: Convexification Approaches for Linepack Modeling," Proceedings of IEEE PES PowerTech 2019

Note: MISCOP: Mixed-Integer Second-Order Cone Program; MILP: Mixed-Integer Linear Program. The simulation represents 50% wind penetration.

An analysis has been conducted on the economic efficiency and CO_2 emission reduction effect of injecting VRE-sourced hydrogen and CN methane into city gas through PtG considering the energy storage capacity of a gas pipeline in Japan[39], in which a simulation was conducted assuming, for simplification, that the gas pipeline is an energy storage facility similar to a gas holder, and that VRE-sourced gas is stored and discharged instantaneously (i.e., city gas supply and demand are in balance hourly). However, for a more precise evaluation of the grid balancing capability of the linepack's storage capability, a fluid dynamic analysis that considers the pressure and flow rate of the gas is required.[40]

3.2. Providing grid services through water electrolysis

Water electrolysis is a necessary piece in the production of hydrogen (and CN methane), playing a key role in decarbonizing gas, and various analyses have been conducted on the possibility of providing grid services, such as grid balancing, using water electrolysis as a means for demand

[38] *Ibid.*

[39] Shibata, Nagata, "*Economic efficiency analysis for injection of hydrogen and carbon neutral methane into existing gas networks*," 37th Conference on Energy, Economy, and Environment, January 2021.

[40] Jing Liu, Wei Sun and Jinghao Yan, "Effect of P2G on Flexibility in Integrated Power-Natural Gas-Heating Energy Systems with Gas Storage," Energies 2021, 14, 196.

response (DR).[41] This is an idea for reducing costs across the entire hydrogen production process by producing hydrogen through water electrolysis while at the same time receiving compensation by providing grid services. In addition to reducing the cost of hydrogen production by raising revenues from grid services, it also helps secure the additional power grid flexibility required for the mass introduction of VRE.

In recent years, efforts for socially implementing this idea have been taking shape in Europe. An EU project named QualyGridS[42, 43], launched in 2017 (under the FCH2 JU (Fuel Cell and Hydrogen 2 Joint Undertaking framework)) (Figure 3-5), has been formulating the test protocol for water electrolysis in order to establish the standard technical requirements for offering water electrolysis as a grid service, and in June 2020, a draft proposal was drawn up[44]. Discussions are also underway at ISO/TC 197 (hydrogen technologies) to set international standards for test protocols and performance evaluation.[45]

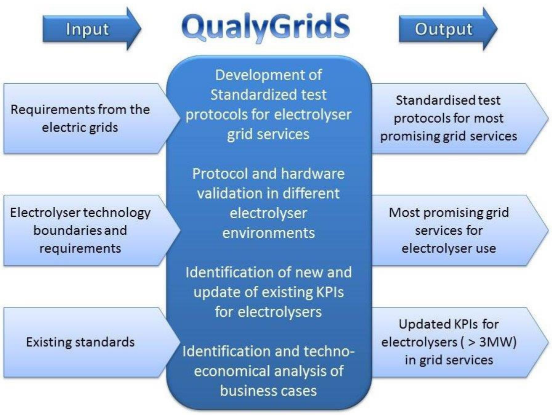

Figure 3-5 Overview of QualyGridS

Source: https://www.qualygrids.eu/

As shown in Table 3-1, water electrolysis is technically compatible with many of the grid services purchased by TSO and DSO of Europe, and combining hydrogen production and grid services is considered extremely rational also from the standpoint of reducing hydrogen production costs. Accordingly, demonstration experiments such as HyBalance[46] and Demo4Grid[47] are being conducted with the support of FCH2 JU.

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41 Shibata, "*Power to Gas business model based on timelines: providing balancing capacity, multi-purpose use, contribution to making renewables a main power source,*" August 2018, IEEJ.
42 https://www.qualygrids.eu/
43 Shi You et al. "Facilitating water electrolysers for electricity-grid services in Europe through establishing standardized testing protocols," Clean Energy, 2020, Vol. 4, No. 4, 379–388.
44 "Qualifying tests of electrolysers for grid services, Finalized testing protocol," QualyGridS.
45 ISO/AWI TR 22734-2 - Hydrogen generators using water electrolysis − Part 2: Testing guidance for performing electricity grid service.
46 http://hybalance.eu/.
47 https://www.demo4grid.eu/.

Table 3-1 Possibility of providing grid services from water electrolysis

Service requester	Service name	Requirements identified by most service requesters	Justification	WE potential
TSO	FCR	Capacity ≥1MW, activation time ≤30s, duration ≥15 min, high ramping requirement, auto symmetrical and dynamic response.	Service designed for generator, normally requires very rapid auto symmetrical dynamic response. In UK, the required activation time for a new service so-called enhanced frequency control is less than 1s. Technically, WEs can meet the requirements if they are designed for such purpose, e.g. running the WEs at 50% load in order to meet the requirements on identical up/down regulation.	Medium
	aFRR	Capacity ≥ 1MW, activation time (second to 15 min) slower than FCR, duration ≥15 min, ramping requirement, auto/remote-controlled symmetrical/asymmetrical dynamic response.	Requires less critical dynamic characteristics than FCR, but higher capacity and longer duration. Technically viable for MW class WEs, provided some technical improvements are made. Use an aggregation-based portfolio to provide such service is feasible. The market might be dominated by generators and large loads.	High
	mFRR	Capacity ≥ several MW, activation ≤15, min duration ≥15 min (up to hours), no ramping requirement, manual controlled messaged-based asymmetrical dynamic/non-dynamic response.	Requires less critical dynamic characteristics than aFRR, but higher capacity and longer duration. Technically viable for MW class WEs, provided some technical improvements are made. Use an aggregation-based portfolio to provide such service is feasible. The market might be dominated by generators and large loads.	High
	RR	Capacity ≥ several MW, activation from 15min to hours, duration ≥15 min (up to hours), no ramping requirement, manual controlled messaged-based asymmetrical static response.	Requires slower response than mFRR, but can be higher capacity and longer duration. Technically viable for electrolysis.	High
	DSR	Requirements are case dependent, can to large extent resemble FCR, aFRR, mFRR and RR.	Tailored for demand to provide TSO services. For countries like UK, DSR is started to be used to provide different kinds of balancing services.	Very high
	Congestion management	Requirements can to certain degree resemble RR. Capacity requirement is normally high.	The remuneration scheme is usually not clear due to the service is very location dependent. This implies only a few large-case WEs sited in designated locations can provide this service.	Medium
	Capacity management	Requirements can to certain degree resemble RR. May also need storage-alike abilities for load shifting etc.	Normally acquired through TSO tailored DSR.	Medium
	Voltage control	Requires WEs to offer reactive power support.	Location dependent. Normally offered by designated large scale units. Remuneration scheme is not clear.	Low
DSO	Congestion management	Requirements can to certain degree resemble RR, but the capacity required will be much lower (e.g. tens of kWs to several MW) and location dependent.	Normally implemented through DSO tailored DSR, are relevant for both MW scale and kW scale WEs.	High
	Capacity management	Requirements can to certain degree resemble RR. May also need storage-alike abilities for load shifting etc.	Normally acquired through DSO tailored DSR.	High
	Voltage control	Requires location dependent WEs to offer reactive power support.	Can be relevant for WEs in microgrids, may require improved ability of grid inverters and the associated control logic.	Medium
	PQ	Location-based service, requirements depend on the specific criteria of PQ service, such as unbalance, voltage management etc.	For WEs, this may require improved ability of grid inverters and the associated control logic. It is possible that the grid operators include the PQ requirements in grid codes, so it is an obligation for WEs to meet the corresponding PQ requirements.	Low
BRP, P2P and other service requesters	Self-balancing	Depends on the requester's portfolio, SCADA and EMS systems etc. Requirements on the dynamic characteristics can be comparable to aFRR, mFRR, and RR when services are about self-balancing. Energy trading oriented energy management will need to consider characters related to unit commitment (e.g. capacity, start/stop time, must on/off duration) and optimal dispatch (e.g. the ability of being modulated).	Notable examples of using WEs to avoid wind curtailment, to improve the portfolio performance (e.g. an integrated wind-hydrogen system) exist. Today, this is one of the major applications for using WEs to support renewable integration.	Very high
	Portfolio optimization			
	Energy trading			

Source: Deliverable Report - Electrical Grid Service Catalogue for Water Electrolyser (D1.1), QualyGridS

4. Implications for Japan

Along with gas decarbonizing using hydrogen and CN methane, Europe is working on using the inherent energy storage capability and flexibility of existing gas networks to ease fluctuations in VRE. In other words, Europe is handling the electric power network and the gas network as components of a comprehensive energy system, and is aiming for a VRE-centered decarbonized society, as shown in Figure 4-1. This concept is the embodiment of energy system integration itself.

The following sections discuss the challenges and possibilities for Japan in using the gas network for gas decarbonization and mass introduction of VRE, respectively, based on the suggestions taken from the developments in Europe.

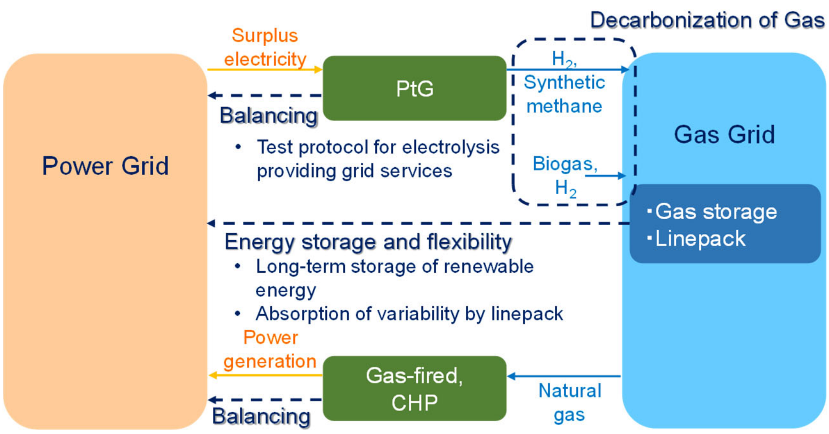

Figure 4-1 Concept of Energy System Integration in Europe

4.1. Decarbonization of gas: Injection of hydrogen and CN methane in city gas

It would seem that the main method for approaching the decarbonization of gas is hydrogen in Europe and CN methane in Japan. Needless to say, the amount of hydrogen and CN methane that will be necessary to replace the entire present demand for gas is vast and sourcing them will take a long time. Therefore, the more common approach is to inject hydrogen and CN methane in small amounts step wisely into the present gas infrastructure. In fact, as shown by France's plan (see 1.1.3), Europe envisions increasing the hydrogen blending ratio each year, aiming to repurpose the existing gas infrastructure for hydrogen and build new infrastructure for 100% hydrogen in the process. However, there are various issues regarding blending hydrogen into gas as described in Chapter 2; Europe fully recognizes these barriers and challenges but apparently plans to proceed by trial and error and revise plans as issues arise. Since the amount of VRE-sourced hydrogen that can be produced changes depending on the VRE capacity, measures must be taken to adapt to the change in the hydrogen blending ratio each year. Responding to time-based fluctuations and regional differences is also a challenge. As described later, it is necessary to verify the extent to which the flexibility of the gas network can be used in energy system integration for coping with these fluctuations.

Meanwhile, Japan is primarily aiming to blend CN methane into city gas, which poses fewer technical barriers regarding blending. Furthermore, the standard CV of the CV regulation system is set to be reduced to 40 MJ/m^3, a value that is close to the CV of methane (see Chapter 2), which also makes the injection of methane easier. However, CN methane has a disadvantage; it is more costly to produce than hydrogen because its production involves the process of separation and capture of CO_2 and methanation in addition to hydrogen production. While the Public-private Council for Promoting Methanation is focusing more on importing CN methane than producing it domestically, regarding this point, it must be noted that CN methane will not help diversify sources of energy import and improve energy security as the existing LNG infrastructure is anticipated to be used. Furthermore, as CN methane generates emissions again when used, the ownership of those emissions will complicate the system design[48]. In particular, imported CN methane will involve the formulation of bilateral rules and international authorization. Designing these institutional systems will be a lengthy process.

Figure 4-2 presents an option that could allow Japan to circumvent both the challenges concerning injecting increasing amounts of hydrogen into the gas network, and the risks associated with the economic efficiency and system design of CN methane. Currently, Japan is supplying imported LNG into the city gas infrastructure and it is the consumers who generate CO_2 emissions; this process can be transformed as shown in Step 1, in which LNG is reformed near LNG terminals to produce hydrogen, which is then supplied to a 100% hydrogen infrastructure built separately. With Step 1, CO_2 will be emitted in the reforming process and consumers will be using gray hydrogen, meaning that this process is basically unchanged from the current process as CO_2 will still be emitted—just at a different place. The next step is importing carbon-neutral LNG (Step 2), which is already underway, and then finally, importing hydrogen in the future (Step 3). By preparing 100% hydrogen infrastructure from the beginning rather than decarbonizing the gas, it will be possible to fully decarbonize in the future just by changing which fuel to import. Furthermore, the key point of this option is that it allows renewable-sourced hydrogen (green hydrogen) made in Japan to be injected into the 100% hydrogen infrastructure without any barriers. Currently, hydrogen, which has a significantly different CV and combustion characteristics, is a “foreign substance” for city gas and is difficult to mix, but blending hydrogen with hydrogen will cause no issues: it will solve all kinds of issues associated with “blending” different gases. Also, the separation and capture of CO_2 and methanation, which are necessary for producing CN methane, will no longer be necessary.

Needless to say, it is not easy for any region to prepare 100% hydrogen infrastructure. Converting city gas infrastructure into hydrogen infrastructure in large cities involves numerous challenges as well as time and costs. Therefore, it is worth considering introducing this scheme within a limited area, in

48 Shibata, Otsuki, “*Essay on sources of carbon in recycled carbon fue*ls *(1) – (4)*,” IEEJ, May 2021.

regions that have a high energy demand density and where building new hydrogen infrastructure is likely to be fairly easy (such as in industrial regions). However, if some consumers in the industrial region need fossil fuel-sourced carbon for special industrial purposes (such as carburizing metals and super-high-temperature heating furnaces), individual responses such as on-site LPG treatment may be necessary.

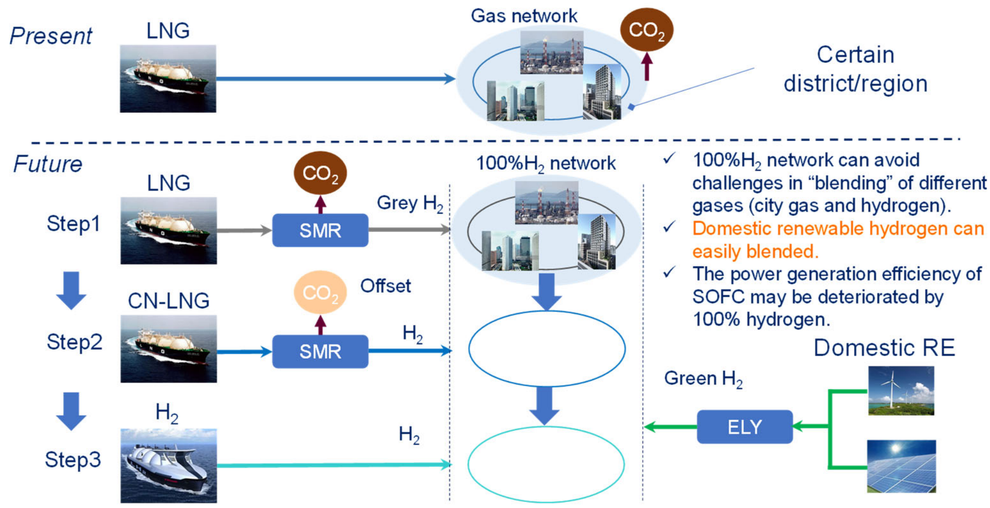

Figure 4-2 Advantages of building 100% hydrogen infrastructure first

Source: Shibata, "*Significance and challenges of new fuels – various forms of hydrogen use –*"; Japan Society of Energy and Resources, Research Committee on "Energy Supply and Demand for Japan toward 2050,", FY2020 Second Symposium (Tenth ESI Symposium), February 4, 2021

4.2. Possibilities and challenges of energy system integration

Europe is pursuing an energy system integration in which electric power and gas networks are handled as components of an integrated whole. This approach suggests that Europe aims to use the flexibility of the gas network, such as energy storage, for expanding VRE capacity, while simultaneously decarbonizing the gas itself. In 2018, ENTSO-E and ENTSO-G jointly announced[49] plans to work together toward energy system integration through PtG, and a significant number of demonstration experiments[50] are underway.

(1) Need for designing new systems: energy storage by PtG, etc.

However, energy system integration through PtG, though technically possible, involves regulatory issues. In February 2021, the European Union Agency for the Cooperation of Energy Regulators (ACER) and the Council of European Energy Regulators (CEER) proposed a basic policy in response to the European Commission's EU Strategy for Energy System Integration (see 1.1.1) released in July

[49] Power to Gas – A Sector Coupling Perspective, ENTSO-E – ENTSOG Joint Paper, October 2018
[50] "*Production of hydrogen from renewables: ideal form of Power to Gas*," Aichi Prefecture "Hydrogen Energy Society Formation Study Group, FY2019, second seminar," November 28, 2019.

2020, in which they summarized the challenges of energy system integration by PtG from the legal system perspective[51]. The proposal recommends that, as energy system integration through PtG covers both the electricity and gas domains, it is necessary to first revisit the definitions of the functions and roles of PtG and competing technologies, while observing the EU's principle of technological neutrality and the selection of technology in a competitive market. In particular, the function and role of energy storage require attention. A PtG plant in itself is not an energy storage facility, though it does contribute to energy storage when including downstream facilities, and therefore, the proposal suggests an amendment of the definition of energy storage set forth in the 2019 Electricity Directive[52] ('energy storage' means, in the electricity system, deferring the final use of electricity to a moment later than when it was generated, (…), and the subsequent reconversion of such energy into electrical energy or use as another energy carrier). It goes on to suggest that when defining PtG as an energy storage facility, it is necessary to distinguish between a PtG facility that is connected only to an electricity network (such as for on-site water electrolysis to cover the hydrogen demand for a plant) or to both the electricity and gas networks. A PtG installation would be considered as an electricity user in the former case. However, as for the latter, it would be considered as an integrating element between the gas and electricity sectors that enables operation of the energy system "as a whole," as formulated in the European Commission's Energy System Integration Strategy.

Regarding energy storage, the regulatory design for leased transmission fees would be an issue. According to a study[53], many European countries waiver or give preferential treatment to leased transmission fees for energy storage technologies. However, for PtG, the interpretation of its energy storage function is complex because the gas produced by PtG is used in non-electric sectors such as city gas and transport. In revisiting the definition of energy storage, including PtG, it must be taken into account that the concept of energy system integration treats electricity and gas as an integrated whole.

As described above, the main issue of energy system integration is how to handle PtG's energy storage function. Other issues include the handling of the flexibility and grid balancing capability inherent to the gas network described in Chapter 3, as well as determining which functions can and cannot be shared between the electricity and gas networks. It may be necessary to integrate parts of the regulatory design of electricity and gas, which is currently conducted separately.

(2) Exploration of energy system integration in view of economic efficiency and other benefits

Economic efficiency is a vital factor in considering the design of energy system integration. As an

[51] Regulatory Treatment of Power-to-Gas "European Green Deal" Regulatory White Paper series (paper #2) relevant to the European Commission's Hydrogen and Energy System Integration Strategies, 11 February 2021.

[52] DIRECTIVES DIRECTIVE (EU) 2019/944 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU.

[53] Shibata, "*Power to Gas business model based on timelines: providing balancing capacity, multi-purpose use, contribution to making renewables a main power source*," August 2018, IEEJ.

example, compare converting the hydrogen produced by PtG back into electricity versus a battery cell. The former has a roundtrip efficiency of just less than 50% (80% for water electrolysis × a generation efficiency of 60% for fuel cells) whereas the latter has an efficiency of 80% (90% for charging × 90% for discharging), making the former far more inefficient; using the hydrogen produced by water electrolysis for power generation is clearly irrational. Therefore, when evaluating fuel cell generation[54], its advantages such as the use of waste heat, distribution of energy sources, and resilience must be taken into account; likewise, for hydrogen gas turbine generation, the inertia of synchronous generators must be considered[55].

We must also remember that the basic aim of energy system integration by PtG is to use the VRE-sourced hydrogen produced by water electrolysis for non-electricity sectors and purposes. However, it is necessary to compare the economic efficiency of energy system integration by PtG, such as injecting VRE-sourced hydrogen and CN methane into existing gas networks to meet the heat demand of the residential and commercial sector, with that of using VRE electricity directly to meet heat demand. The former has an efficiency of about 70% (80% for water electrolysis × 90% for water heaters) and the latter 90–300% (from electric water heaters to heat pump hot-water suppliers), making the former decisively more inefficient.

As described, energy system integration through PtG offers little benefit if we look only at energy and economic efficiency. This makes it important to explore how to create value from the energy storage function and flexibility of "well-established (IEA)" existing gas networks, such as using them to ease fluctuations associated with the mass introduction of VRE, as described in Chapter3, and to design a regulatory system for implementing this concept.[56] However, for this to be done, it is necessary to technically evaluate the flexibility of gas holders, storages in underground caverns in some regions (in Niigata, etc. in Japan), and linepacks of pipelines, which is a challenge.

Resilience is another important perspective. The additional resilience of the entire energy system obtained by operating electric and gas networks as an integrated whole has been presented as a benefit of energy system integration at the Study Group on the Future of the Gas Business toward 2050.

(3) Short-term perspective: Supply-demand grid balancing by water electrolysis

Evaluating the additional flexibility and resilience provided by gas networks involves numerous tasks including preparing necessary data and establishing analysis systems, and will take a long time

[54] Kawakami, "*The Value of Energy Storage in the Decarbonized Energy System: An Energy System Optimization Approach Considering Non-synchronous Power Generation Constraints,*" Transactions of the Institute of Electrical Engineers of Japan. B (a publication of the Power and Energy Society), IEEJ Transactions on Power and Energy, Vol. 141 No. 5 pp. 326–335.
[55] Shibata, "*The form of Power to Gas necessary for reaching carbon neutrality in 2050,"* Japan Society of Energy and Resources FY2021 Third Energy Policy Roundtable, "*Expectations for and Challenges of Power to Gas and Hydrogen Carriers toward Carbon Neutrality*," September 17, 2021.
[56] Shibata, "*Renewable energy storage using hydrogen*," The Japan Institute of Energy Journal "enerumikusu," 100, 161–167 (2021).

when including the subsequent regulatory system design process. Therefore, in the short term it is important to discuss how to utilize water electrolysis, which is the core technology of PtG, as a supply-demand balancer of electricity (see Chapter 3). In Japan, NEDO is conducting demonstration projects in this area. The idea of using gas cogeneration (CHP) as a source of the grid balancing capability necessary for mass introduction of VRE is already underway primarily in the gas industry, but efforts should also be launched as soon as possible on using water electrolysis for supply-demand balancing as well. Providing grid balancing capability through demand response using water electrolysis will generate profits, which in turn will help reduce the cost of hydrogen production.[57]

(4) Other points to note

- Value of excess renewable electricity

As described above, using water electrolysis for supply-demand balancing requires grid electricity supplies, and as such, the CO_2 emission coefficient of the hydrogen produced will be determined by the power generation mix. There is no issue if the power source is sufficiently decarbonized, but to produce hydrogen with a low CO_2 emission coefficient, the ideal source would be excess VRE electricity. In particular, from the standpoint of energy system integration, it would be rational to use VRE preferentially for electricity, and to supply any excess VRE-sourced electricity to the gas network. Here, the price of excess electricity is crucial. It is often thought that excess electricity is inexpensive because when it arises, wholesale electricity prices are zero or negative, and therefore, excess electricity can greatly reduce the cost of hydrogen production. However, excess electricity is inexpensive only for small water electrolyzers with no impact on the electricity supply-demand balance; when electrolyzer capacities increase, so does the demand for electricity at times when excess electricity is generated, pushing up wholesale electricity prices as a result.

In other words, producing hydrogen from excess electricity creates a demand for excess electricity, and at that moment the electricity is no longer an "excess" and its price increases. Therefore, it is impossible to secure excess electricity inexpensively for producing hydrogen in amounts large enough to decarbonize gas; in conclusion, it will be necessary to significantly reduce the generation cost of VREs themselves to improve economic efficiency.

- Additionality of renewable energy

The reason for mentioning above that the use of excess electricity is ideal for hydrogen production concerns additionality.[58] The meaning of additionality here is that when producing hydrogen from renewable energy, it must be produced from a renewable energy supply introduced additionally. If the

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[57] Shibata, "*Power to Gas business model based on timelines: providing balancing capacity, multi-purpose use, contribution to making renewables a main power source*," August 2018, IEEJ.

[58] Shibata, "*Role of Power to Gas and methanation toward a low-carbon society,"* "Inorganic film opens path into the future: Environment and Energy Technology Symposium, RITE, November 7, 2019.

renewable energy that is already in operation for decarbonizing electricity is diverted to hydrogen production, other power sources must be installed to cover the decrease in output, which would be irrational. To avoid this, Germany and others have been working on formulating relevant standards since around 2017.[59] As it is difficult to set a precise standard, the standard is based on the number of years a renewable energy plant has been in operation.

Meanwhile, since excess electricity is something that the electricity grid cannot use and will be discarded, the debate on additionality does not arise. Even so, when using excess electricity to produce hydrogen, its economics must still be compared with other grid integration measures such as batteries, use of inter-regional transmission lines, and so on.

Conclusion

This report presented an overview of efforts underway in Europe toward gas decarbonization and energy system integration, and described the challenges and possibilities of these measures through comparison with the efforts and discussions underway in Japan.

Europe and Japan have major differences in their networks and regulatory systems, but are also similar in that both have scarce biogas resources and their options for gas decarbonization are limited to hydrogen and hydrogen-sourced CN (carbon neutral) methane. The challenge for both parties is how to obtain hydrogen and CN methane and inject them into the gas network. Europe is planning to increase the hydrogen blending ratio in existing gas networks in stages, with a view to repurposing the gas networks for 100% hydrogen and building new hydrogen infrastructure in the process. Meanwhile, Japan's main approach is to blend CN methane into city gas, and has set a policy direction to lower the standard CV to 40 MJ/m^3, close to that of methane.

Gas decarbonization requires significant amounts of hydrogen and CN methane, which Japan may need to purchase from other countries. However, it is also important to pursue the concept of energy system integration, in which the gas network, inclusive of Power to Gas and cogeneration, is used to address output fluctuations associated with the mass introduction of domestic VRE to build a decarbonized economy, while also decarbonizing the gas itself by including VRE in the process. This is because existing electric power networks alone will not be able to cope with the enormous amounts of VRE that will need to be introduced. New measures such as strengthening inter-regional transmission lines and batteries may not be sufficient. Meanwhile, existing gas networks are already equipped with an energy storage capability and flexibility owing to the physical characteristics of the gas; incorporating Power to Gas into the networks will allow these functions to be used to mitigate VRE output fluctuations. In other words, the gas network is inherently highly compatible with VRE.

[59] The green hydrogen standard of Germany's third-party test certification organization TÜV SÜD CMS 70 Standard (12/2017) requires that electricity from new renewable plants (within 3 years after construction) must account for a certain level (30% or more). The Clean Energy Partnership's standard stipulates that at least one-third must be from a renewable energy plant within 6 years and another one-third from a plant within 12 years after construction.

Needless to say, it will be necessary to evaluate what kinds of measures will be economically efficient for dealing with the mass introduction of VRE, but based on the above, utilizing well-established existing gas networks is an option worth considering. Europe is making progress with discussions on energy system integration, and has begun specific discussions on revisiting the definition of energy storage technology and on providing grid balancing capability using water electrolysis.

Energy system integration is also valuable from the perspective of resilience. From the efficiency perspective, it is preferable to use VRE-sourced hydrogen from PtG and CN methane for producing heat. However, by using water electrolysis and CHP to ease VRE output fluctuations and stored hydrogen and CN methane for emergencies, the overall resilience of the energy system will be enhanced. In this case, it may be possible to further optimize energy system operations if electricity and gas networks can be operated in a coordinated manner.

Meanwhile, as energy system integration involves both electricity and gas, various regulation-related issues must be resolved to achieve it, such as the definition of energy storage and the use of grid balancing capacity. Before this can be done, it is necessary to determine how much flexibility the entire gas network has, including gas holders and the linepack of pipelines.

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