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SCOPE FOR EU–JAPAN COOPERATION IN DECARBONISING THE GLOBAL LNG MARKET

Abstract

Background: Global climate ambitions seem to be at odds with the future use of natural gas. However, the inability to fully electrify the demand for energy has forced developed economies to seek ways to decarbonise the gas industry. This article investigates the option to further use LNG terminals as a source of carbon-neutral energy supply for the EU and Japan, which together account for 50% of the global demand for LNG.
Research purpose: The aim of this paper is to verify the potential pathways toward continued utilisation of the EU and Japanese LNG infrastructure in a low-carbon or even climate-neutral future.
Methods: A literature review of different technologies that enable CO_2-neutral gas production or imports is conducted to identify potential pathways for decarbonisation. A SWOT analysis of the two selected scenarios is then performed to present their upsides and downsides and to identify potential areas for cooperation. Finally, the costs associated with the two development paths are analysed to verify where the main challenges lie.
Conclusions: The study confirms that the success of gas conversion facilities will rely heavily on technological advancements that would reduce the unit cost of natural gas processing. By contrast, biomethane imports will require operational support to effectively compete with other energy carriers. The author concludes that both gas decarbonisation scenarios analysed may well prove to be complementary. However, access to financing will likely pose a major challenge to the future utilisation of the existing LNG infrastructure.

Keywords: LNG, international trade, decarbonisation.

JEL Classification: Q56, L95, F64, Q42

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1. Introduction

The first liquified natural gas (LNG) carrier was constructed in 1959, marking the start of a new area of gas trading outside pipelines and over long distances. The early days of the LNG business were based on constructing dedicated vessels to connect infrastructure on specific routes. In the middle of the 1990s, there were approximately 80 vessels serving point-to-point transactions.[1] Over the next decade, the business flourished, with South Korea's shipyards entering the competition over LNG vessel construction. Carriers became much larger, and as their costs dropped, they became far more popular.[2] The more recent wave of LNG shipping development was brought about by the development of "floating" LNG solutions, which enable the ships to be repurposed from fuel transporters to receiving and liquefaction facilities. They have proved to be much cheaper than the traditional terminals, enabling economic exploitation of previously inaccessible gas fields and multiplying opportunities for traders.[3] The development of global liquified gas trading was also underpinned by international arrangements that supported the free movement of goods and technical standardisation. Great efforts in this context have been made by the International Maritime Organisation (IMO) under the auspices of the United Nations, as well as the Society for International Gas Vessel and Terminal Operators (SIGTTO).[4] The number of LNG ships increased from 360 to 601 between 2010 and 2020.[5]

The gas industry was first developed by state-owned, vertically integrated companies that were responsible for gas production or acquisition, transport, and delivery to end-users. Pipeline-based transportation was most popular in the USA and Europe, while LNG shipping developed in Asia. In both cases, a gas sale and purchase agreement was a long-term arrangement that imposed a number of constraints on the parties to the transaction.[6] For LNG agreements, these constraints went beyond the typical take-or-pay clauses, including, e.g.:[7]

1 **J. Robin**, **V. Demoury**, *The LNG Indus*try, "International Group of Liquefied Natural Gas Importers", Neuilly-sur-Seine 2011, pp. 1–30.

2 **D. Gardner**, *LNG shipping*, in: **P. Griffin**, *Liquefied Natural Gas. The Law and Business of LNG*, Global Law and Business Ltd., Surrey 2017, pp. 7–11.

3 **IGU**, *Global Renewable and Low-Carbon Gas Report*, IGU, Barcelona 2021, pp. 20–21.

4 **SIGTTO**, *Annual report and Accounts*, London 2020, pp. 1–35.

5 https://www.statista.com/statistics/468412/global-lng-tanker-fleet/; accessed 7.07.2021.

6 **A.J. Melling**, *Natural gas pricing and its future. Europe as the battleground*, Carnegie Endowment for International Peace, Washington D.C. 2010, pp. 127–135.

7 **H.W. Sullivan**, *LNG sale and purchase agreements*, in: **P. Griffin**, *Liquefied Natural Gas, Global Law and Business*, Surrey 2017, pp. 185–213.

- A destination clause – a provision of the contract that predefines the delivery point of the contracted cargoes. Although particularly restrictive, such arrangements still underpin many transactions and may be of the utmost importance to importing countries where an LNG terminal is the primary, if not the sole source of natural gas. From a business relationship point of view, the destination clause can also imply responsibility for the delivery;
- volume adjustment mechanisms – optionality to modify the amount of gas sold, typically applicable if the seller also acts as a supplier on the market where the commodity is delivered;
- consent before sale – a requirement for the seller to acquire the client's consent for any further sales in his country.

As the LNG market grew in size and geographical reach, restrictive clauses were increasingly replaced by free-on-board arrangements, where the responsibility for transport is transferred from the seller as soon as the commodity is loaded onto a ship.[8] There are also other limitations that prevent full freedom of moving the cargo (e.g., the scope of the ship's insurance and its compatibility with receiving facilities). However, these are increasingly overcome by new solutions that include lightering (ship-to-ship cargo transfers) and cargo swaps.

Future growth of the industry seems promising despite the more recent criticism of natural gas as a fossil fuel that does not fit the carbon-neutral future proclaimed by most developed economies. Emissions from natural gas combustion remain a fact, and LNG transport also results in quite substantial methane leakage.[9] At the same time, the transition from far more polluting technologies based on hard coal, lignite, or oil toward natural gas has considerable emission abatement potential that should not be underestimated.[10] Further restrictions on CO_2, SOx, and NOx emissions will continue limiting the attractiveness of natural gas, although at a different pace in different regions of the world. Nonetheless, many national energy strategies still look to natural gas as an important "transition fuel" towards carbon neutrality, as it is becoming increasingly acknowledged that not all energy use can be electrified.[11]

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[8] **M. Javid**, **E. Shahmoradi**, *Risk Management in LNG Shipping Arrangements*, Oil, Gas & Energy Law Intelligence 2016/4, p. 3.

[9] **J. Herdzik**, *Methane slip during cargo operations on LNG carriers and LNG-fueled vessels*, New Trends in Production Engineering 2018/1 (1), pp. 293–299.

[10] **J. Weiss et al.**, *Electrification. Emerging Opportunities for Utility Growth*, The Brattle Group, Boston 2017, pp. 5–11.

[11] **L. van Nuffel et al.**, *Sector coupling: how can it be enhanced in the EU to foster grid stability and decarbonize?*, European Parliament, Brussels 2018, pp. 51–56.

The liquidity and flexibility offered by the global gas market provide good arguments for both the European Union (EU) and Japan to remain part of it. Both European and Japanese demand for gas is still expected to exist in 2050 and beyond, and these countries have invested time and substantial funds in developing the necessary infrastructure connecting them to the global market for gas.[12] The aim of this paper is to verify the potential pathways toward the continued utilisation of the EU and Japanese LNG infrastructure in a low-carbon or even climate-neutral future.

2. Literature review – LNG financing and decarbonisation

The development of multiple liquefaction facilities around the world and the increasing attractiveness of gas as a fuel have shifted the market power from large national incumbents onto agile entities that can effectively profit from short-term shifts in the underlying commodity prices. That also means that flexibility in contracts became far more attractive than long-term exclusive arrangements. The shift has unlocked new potential for competition, but, at the same time, it made the economic modelling of new terminals far more complex.

The traditional approach to deciding to invest in an LNG terminal was securing commitments for at least 80% of the intended terminal capacity under long-term offtake contracts, preferably with a take-or-pay clause.[13] Project financing typically involves a number of stakeholders tied into a transaction through the intermediation of a special purpose vehicle (SPV).[14] The stakeholders are credit institutions, entities with a direct interest in future terminal use, host country governments, and export credit agencies (ECAs). Attracting sponsors requires considerable effort from the project promotor, not only in terms of presenting robust numbers on the project's profitability, but also in terms of the envisaged risk management related to the project's environmental and social impact. There are also multiple other risk areas that should be addressed in a project's business plan, and these need to be catered for. Under the revised

12 **M. Catuti et al.**, *The future of gas in Europe: Review of recent studies on the future of gas*, on-line 2019, CEPS Research Report 2019/03, pp. 11–17; https://www.numo.or.jp/topics/1-1Nakanishi.pdf; accessed 3.07.2021.

13 **World Bank**, *Introduction of Liquefied Natural Gas (LNG) in Central America*, Economic Consulting Associates Ltd., London 2015, p. 90.

14 **E. Adesina et al.**, *Global LNG Fundamentals*, Book Sprint, Washington D.C. 2017, pp. 143–150.

Basel Accords, banks have become very selective in terms of their involvement in high-risk projects.[15]

New technologies, gas extraction fields in new locations and other, unconventional gas sources (e.g., biomethane, shale gas) all bring about new challenges related to gas quality. Quality considerations have always been particularly challenging in the LNG industry, as they are specified in a transaction's confirmation notice and have to be met at the time of delivery. A cargo that does not meet the specification can be rejected, and the buyer may be entitled to compensation. Quality standards are, therefore, an important area where cooperation between the largest gas importers (such as the EU and Japan) can support maintaining the integrity of the global market for gas, as homogeneity is of key importance when establishing a wholesale market.

As mentioned in the previous section, the prevalent view is that full electrification of energy consumption is not a viable scenario. Thus, countries across the globe have been forced to seek alternatives to fossil fuels, such as biomethane, synthetic methane, and hydrogen. Biomethane is biogas produced from anaerobic digestion, upgraded to the quality of natural gas through different technologies, whereas synthetic methane is produced from hydrogen and carbon dioxide in a process called methanation.[16] The challenge with these technologies (hydrogen production from electrolysis and synthetic methane production with renewable characteristics) is that they are either immature or do not have the capacity to effectively replace natural gas, not least to the extent that would enable either the EU's or Japan's self-sufficiency in this area.[17] The potential to import these alternative fuels poses a challenge of its own:

- The challenge lies in ensuring that the production of these alternative fuels is done in a sustainable (or at least environment-friendly) manner. With biomethane, this relates to the feedstock used – in particular, the energy-food dilemma.[18] With hydrogen, current technologies allow it to be

[15] **K. Zielińska**, *Financial Stability in the Eurozone*, Comparative Economic Research 2016/19 (1), pp. 168–169.

[16] **M. Prussi et al.**, *Review of technologies for biomethane production and assessment of EU transport share in 2030*, Journal of Cleaner Production 2019/222, pp. 565–572; **W. Becker et al.**, *Production of Synthetic Natural Gas from Carbon Dioxide and Renewably Generated Hydrogen: A Techno-Economic Analysis of a Power-to-Gas Strategy*, Journal of Energy Resources Technology 2019/141, pp. 2–11.

[17] **L. van Nuffel et al.**, *Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure*, European Parliament, Brussels 2019, pp. 1–5.

[18] **E. Tamburini et al.**, *Biogas from agri-food and agricultural waste of can appreciate agroecosystem services: The case study if Emilia Romagna region*, Sustainability 2020/12, pp. 1–15.

produced at an industrial scale by separating it from fossil fuels and do not really support decarbonization;
- Technical constraints limit the usability of the existing LNG assets in transporting alternative fuels. Repurposing these assets would require significant investment, especially if they are to facilitate imports of hydrogen.[19]

Respective production facilities that export "clean" energy carriers need to be credibly certified as sources of renewable or low-carbon gas according to the receiving country's taxonomy. Discrepancies can result in different exporting facilities being effectively restricted to exports in only a single direction where the sustainability characteristics of the exported product is properly documented.[20] While there may be merit in deliberately limiting the export capability to a single importing country or region, considering the size of the investment needs and the urgency to tackle climate change, such an approach would be counterproductive and would fragment the wider market to the disadvantage of the importing countries in the long-term.

Further down the process, renewable energy carriers need to be transported to EU and/or Japanese terminals, and therefore proximity remains a factor that determines the delivery costs.[21] Nonetheless, it should not discourage cooperation between the largest importers of LNG, as they are already competing over the same gas resources around the world.

In the future, sustainability considerations are expected to play a far greater role in terms of access to financing. This may well be a positive change to entities involved in trading low-carbon or renewable gases, if that allows access to additional revenue streams for the green value of the underlying commodity. In addition, strict sustainability criteria can crowd out fossil-based technologies from competing over access to financing. Potential scenarios for carbon-neutral gas imports into the EU and Japan will be analysed in the next chapter.

[19] **A.J.M. van Wijk**, **F. Wouters**, *Hydrogen. The bridge between Africa and Europe*, Springer, Berlin 2019, pp. 1–28.

[20] **International Energy Agency**, *Outlook for biogas and biomethane*, IEA Publications, Paris 2020, p. 68.

[21] **P. Lont**, *Competition on the LNG market – consequences for the EU*, Prace Naukowe Uniwersytetu Ekonomicznego we Wrocławiu 2020/64 (6), pp. 135–137.

3. LNG infrastructure decarbonisation scenarios

Further considerations will focus on the economics of the solutions that can potentially allow the use of existing LNG terminals and vessels in the future, retaining access to the global market. Different pathways for making Europe's LNG infrastructure fit for the climate-neutral future were analysed in a study by Frontier Economics. They showed that:[22]

1. Liquified gas imports can remain focused on natural gas that is then processed into hydrogen or a gas blend acceptable by the gas grid;
2. The focus is shifted onto imports of biomethane or synthetic methane, neither of which is of fossil origin.

The Frontier study also considered alternatives where hydrogen is produced and imported in different forms into Europe, which would mark the rollout of a different market to the one analysed in this study. Therefore, they will not be analysed further in this article. The case study will analyse two approaches that the EU and Japan can take to decarbonising the LNG infrastructure:

1. Scenario 1 envisages additional investment in technologies to convert the imported natural gas into hydrogen at the terminal.
2. Scenario 2 assumes that the LNG carriers bring only biomethane and/or synthetic methane that is produced in third countries.

The two scenarios are equally appealing to Europe and Japan for several reasons:

1. The EU and Japan would remain part of the global market for natural gas. This means:
   a. Access to competitive sources of natural gas;[23]
   b. A diverse portfolio of suppliers, which improves the security of supply also in the political context;
   c. A flexible supply of gas, which can adapt both to the short-term and seasonal demand fluctuations. This is particularly important when a large share of imported gas is used for electricity production, like in Japan;[24]
   d. Expertise established in managing the LNG infrastructure, as well as in operating in the LNG market, will be retained;

[22] **D. Roberts**, **M. Janssen**, *The role of LNG in the energy sector transition. Regulatory recommendations*, "Frontier Economics", London 2020, pp. 2–60.

[23] **International Energy Agency**, *Japan 2021 Energy Policy Review*, IEA Publications, Paris 2021, pp. 3–19.

[24] **International Energy Agency**, *LNG Market Trends and Their Implications*, IEA Publications, Paris 2019, pp. 2–6.

2. Existing infrastructure and vessels could be utilised for years to come, which is a notable advantage when considering the amount of money invested in them already;[25]
3. Both the EU and Japan gain better prospects for decarbonising their energy demand.

The two scenarios also have distinct flaws that need to be borne in mind. Imports of synthetic methane or biomethane imply that these gases would be produced outside the jurisdiction of either the EU or Japan.[26] This means there will be challenges associated with certifying the facilities as renewable within the understanding of the applicable regulations. In terms of converting natural gas at the receiving terminals, the most immediate downside is retaining the reliance on fossil fuel that is to be converted into hydrogen.

Both scenarios envisage that additional investment will be necessary at different points of the value chain. This should encourage further considerations around enhanced cooperation between the EU and Japan to support investment in the relevant technologies at scale. The study begins with a SWOT analysis for both scenarios to factor in all the different aspects that need to be considered before assessing the costs associated with a given pathway.

4. SWOT analysis for scenarios 1 and 2

TABLE 1: *SWOT analysis – Scenario 1*

Strengths	Weaknesses
• The EU & Japan remain part of the global LNG market • LNG facilities continue to offer additional supply flexibility to the gas sector[a] • Decarbonisation technologies applied at terminals need to be compliant with national/EU law • LNG assets used for importing gas do not become stranded, or their redundancy is limited	• Substantial investment is needed to ensure the gas-to-hydrogen conversion functionality of the LNG terminals • Decarbonisation technologies are still at an early stage of development • CO_2 storage technologies are still at an early stage of development, and there are few supranational projects on developing the relevant infrastructure • The EU and Japan remain dependent on fossil fuel imports

[25] **IGU**, *World LNG Report*, IGU, Barcelona 2021, pp. 1–68.
[26] **IGU**, *Global Renewable and Low-Carbon Gas Report*, IGU, Barcelona 2021, pp. 1–49.

Opportunities	Threats
• Gas converted at terminals may be subsidised for its contribution to decarbonisation targets • Receiving terminals can be recognised as contributing to the economy's transition to carbon neutrality and, as such, can be financed under the sustainable finance initiatives	• Certificates for renewable and low-carbon gases may not recognize the emission reduction offered by conversion technologies applied at terminals or can do that exclusively in certain countries or regions, potentially distorting competition[b] • Decarbonisation technologies do not become sufficiently mature to allow timely conversion of the imported natural gas

Explanatory notes:

[a] This point relates both to the fact that LNG carriers can be diverted to markets with increased gas demand in the short term and to markets that used to rely on a single source of gas before the terminal became operational;

[b] Instruments certifying the origin of the energy produced (e.g., Guarantees of Origin) may or may not record the share of carbon emissions that are captured and stored. The type of information disclosed in a certificate is subject to a vivid discussion under different projects (e.g., FastGO, CertifHy).

Source: own elaboration.

The SWOT analysis of both scenarios shows that they can enable the use of existing LNG assets in the future, and as such, they should not be perceived as mutually exclusive. Converting biomethane into hydrogen with carbon capture and storage results in the creation of an energy carrier with negative greenhouse gas emissions.[27] Given that there are no biomethane exporting countries just yet, Scenario 1 could be viewed as an interim step towards the future decarbonisation of the gas sector, provided that the EU and Japan can stimulate pilot projects for natural gas conversion and carbon capture and storage.

The results of analysing both scenarios also point to several areas where increased coordination between the EU and Japan could bring tremendous benefits or enshrine competition on a global level. These areas primarily involve:

- Common standards for recording greenhouse gas emissions that can serve as the basis of a global emissions price that would help establish a level-playing field between different technologies and improve the competitive position of renewable and low-carbon technologies vis-à-vis fossil fuels;

[27] **C. Antonini et al.**, *Hydrogen production from natural gas and biomethane with carbon capture and storage – A techno-environmental analysis*, Sustainable Energy & Fuels 2020/4, pp. 2967–2986.

- Joint R&D projects in the areas of carbon capture and storage and gas-to-hydrogen conversion technologies;
- Common criteria for recognising sustainability of energy carriers leading to common, or at least mutually recognised instruments verifying the origin of these carriers;
- Coordinated financial support to facilities capable of exporting biomethane/ synthetic methane to share the financial burdens and prevent distortions to competition in the gas market.

Quantitative analysis of the financial side of the challenge associated with the transition to a low-carbon economy under both scenarios requires a set of assumptions, starting with selecting the technological solutions to be analysed. Desk research indicates that only steam methane reformation appears to be a readily available commercial application at scale in the coming years.[28] Some studies also point to methane pyrolysis in thermal plasma reactors as sufficiently developed, although their application so far has been experimental.[29] The widespread commercial upgrading of biogas to biomethane analysed under Scenario 2 confirms the technological readiness of these installations.

TABLE 2: *SWOT analysis – Scenario 2*

Strengths	Weaknesses
• Biomethane production replaces natural gas, reducing the EU and Japan's dependence on fossil fuel imports • The same carriers and terminals can be used to liquify and regasify biomethane in the future • LNG terminals continue to offer additional supply flexibility to the gas sector • LNG assets used for importing gas do not become stranded, or their redundance is limited	• No sizeable export capacity of either biomethane or synthetic methane currently exists; substantial investment is needed to develop their production and associated infrastructure to allow exports • Biomethane produced outside the EU or Japan does not fall under the scope of the rules and requirements set for their production domestically[a]

[28] **A. Al-Qahtani et al.**, *Uncovering the true cost of hydrogen production routes using life cycle monetisation*, Applied Energy 2021/281, p. 2.

[29] **S. Schneider et al.**, *State of the Art of Hydrogen Production via Pyrolysis of Natural Gas*, ChemBioEng Reviews 2020/7 (5), pp. 150–157; **S. Timmerberg et al.**, *Hydrogen and hydrogen-derived fuels through methane decomposition of natural gas – GHG emissions and costs*, Energy Conversation and Management: X 2020/7, p. 5.

Opportunities	Threats
• The EU and Japan may offer investment and operational subsidies for the production of biomethane that is intended for exports[b] • Developing multiple locations to export biomethane may result in greater competition and efficiency • An increase in the global prices of CO_2 emissions may increase the competitiveness of biomethane[c] • Receiving terminals should be recognised as infrastructure that contributes to the economy's transition towards carbon neutrality, and as such, it can be financed under sustainable finance initiatives	• Certificates for renewable and low-carbon gases may not cover production facilities outside the EU and/or Japan, respectively • The list of feedstock permissible under the sustainability criteria may prove to be insufficient to underpin the regasification capacity of all the EU and Japanese terminals[d].

Explanatory notes:

[a] The challenge is that the non-fossil origin of the energy carrier in question does not immediately imply its sustainability. Further consideration is needed regarding the feedstock used, e.g., to ensure that the renewable gas is not produced from crops that replace food production.[30]

[b] This point may well be perceived as a threat, as access to financing may be a precondition to the development of biomethane production in many countries, especially in Africa.[31]

[c] This opportunity should be considered with due attention given to the challenge that greenhouse gas emission calculations pose to the producers and certifying bodies.[32]

[d] The criteria set for biomethane production today vary from Member State to Member State, and the lack of coordination has already proved to have significant distortive potential.

Source: own elaboration.

5. Calculation results – costs under Scenario 1

Two technology types will be considered in terms of decarbonising LNG at terminals in the EU and Japan: steam methane reformation with carbon capture and storage (SMR with CCS) and pyrolysis in thermal plasma reactors. A summary of the costs associated with both technologies is presented in Table 3.

[30] **J. Popp et al.**, *The effect of bioenergy expansion: Food, energy, and environment*, Renewable and Sustainable Energy Reviews 2014/32, pp. 559–578.

[31] **G.V. Rupf et al.**, *Broadening the potential of biogas in Sub-Saharan Africa: An assessment of feasible technologies and feedstocks*, Renewable and Sustainable Energy Reviews 2016/61, pp. 556–571.

[32] **K. Oehmichen et al.**, *Technical principles and methodology for calculating GHG balances of Biomethane*, DFBZ, Berlin 2016, pp. 1–52.

TABLE 3: *CAPEX and OPEX of different hydrogen production technologies*

Technology	CAPEX [EUR/kWh H_2]	OPEX [EUR/kWh H_2]
SMR with CCS	1,399.20	0.051
Methane pyrolysis	3,940.00	0.033
SMR with CCS (2050)	934.00	0.051
Methane pyrolysis (2050)	1,261.00	0.033

S o u r c e: own elaboration based on **L. van Cappellen et al.**, *Feasibility study into blue hydrogen. Technical, economic an sustainability analysis*, CE Delft, Delft 2018, p. 11; **S. Schneider et al.**, *State of the Art of Hydrogen Production via Pyrolysis of Natural Gas*, ChemBioEng Reviews 2020/7 (5), pp. 150–157; **R. Sarsfield-Hall**, **B**. **Unger**, *Utilizing the versatility of hydrogen to fully decarbonise Europe*, "Poyry Decarbonisation Services", Stockholm 2019, p. 1; **International Energy Agency**, *The future of hydrogen*, IEA, Paris 2019, p. 42.

The technical capacity of installations using both technologies has been assumed at 225,000 kWh of hydrogen per hour (approx. 20,000 m^3). The size of these appliances should allow for the processing of natural gas being unloaded from even a large LNG carrier. For steam methane reformers, appliances of this size are readily available, whereas the assumed size of a thermal plasma reactor is purely theoretical to enable unbiased cost comparison. The technological lifetime of both solutions has been set to 20 years, and their annual availability has been set to 8400 hours per year based on the assumed progress in plasma-based technologies.[33] That level of availability would also match the assumed availability of biogas upgrading plants analysed under Scenario 2. The related costs per installation, along with the resultant levelised cost of hydrogen (LCOH), are presented in Table 4 below.

TABLE 4: *Levelised cost of hydrogen produced from different technologies*

Investment cost per installation	CAPEX [EUR mln]	Lifetime OPEX [EUR mln]	LCOH [EUR/kWh H_2]
SMR with CCS	314.820	1,898.590	0.059
Plasma Pyrolysis	886.500	1,241.100	0.057
Future SMR with CCS	210.150	1,898.590	0.056
Future Plasma Pyrolysis	283.725	1,241.100	0.041

S o u r c e: own elaboration.

[33] **J. Hrbek**, *Status report on thermal gasification of biomass and waste 2019*, "IEA Bioenergy Task 33 Special Report", Paris 2019, pp. 1–125.

LCOH is a version of the more common indicator called levelised cost of energy (LCOE) and is a tool for comparing the unit cost of energy produced using different technologies. When measuring hydrogen, it is typically calculated per kilogramme of hydrogen produced. Hence, for ease of comparing the results, they have been converted assuming the energy content of 33.6 kWh/kg H_2.[34] The results are referenced against the numbers presented by Al-Qahtani et al. and by Brandle et al. in Table 5 below.[35]

TABLE 5: *Levelised cost of hydrogen – comparison*

Technology	Al-Qahtani et al. (2021)	Brandle et al. (2020)	LCOH calculated	Future LCOH calculated
	LCOH [EUR/kg]	LCOH [EUR/kg]	LCOH [EUR/kg]	LCOH [EUR/kg]
SMR+CCS	1.703	2.034	1.978	1.884
Pyrolysis	1.585	1.695	1.915	1.372

Source: own elaboration based on **A. Al-Qahtani et al.**, *Uncovering the true cost of hydrogen production routes using life cycle monetisation*, Applied Energy 2021/281; **G. Brandle et al.**, *Estimating Long-Term Global Supply Costs for Low-Carbon Hydrogen*, EWI Working Papers, Koeln 2020.

The results point to notable discrepancies between both studies and calculations under Scenario 1, particularly regarding pyrolysis. The difference between both reference studies may result from different pyrolysis technologies being analysed (molten-metal reactor, and different exchange rates used for calculations[36]). It is also interesting to note that EWI's assumed SMR-based LCOH is higher than that calculated either in this study or by Al-Qahtani et al.[37] This difference can be attributed to the fact that the Brandle et al. report factors in the costs of CO_2 emissions that are not captured and stored.

Hydrogen produced at LNG terminals will have to compete with hydrogen produced domestically through electrolysis and hydrogen extracted from

[34] http://www.h2data.de; accessed 15.08.2021.

[35] **A. Al-Qahtani et al.**, *Uncovering the true cost of hydrogen production routes using life cycle monetisation*, Applied Energy 2021/281, pp. 1–12; **G. Brandle et al.**, *Estimating Long-Term Global Supply Costs for Low-Carbon Hydrogen*, EWI Working Papers, Koeln 2020, pp. 1–60.

[36] **R. Dagle et al.**, *An Overview of Natural Gas Conversion Technologies for Co-Production of Hydrogen and Value-Added Solid Carbon Products*, EERE and Transportation Office. Fuel Cell Technologies Office, Washington D.C. 2017, pp. 1–73.

[37] **G. Brandle et al.**, *Estimating Long-Term Global Supply Costs for Low-Carbon Hydrogen*, EWI Working Papers, Koeln 2020, pp. 49–52.

pipeline-imported natural gas. Since liquified gas imports can already compete with natural gas imported via pipelines, the competitive position of LNG should remain largely unchanged. Available estimates of electrolysis-based LCOH signal that natural-gas based hydrogen will continue to have a significant competitive advantage by 2050 and possibly beyond (see Table 6).

TABLE 6: *Levelised cost of hydrogen from electrolysis*

Electricity source	Al.-Qahtani et al. (2021)	Brandle et al. (2020)
	LCOH [EUR/kg]	LCOH [EUR/kg]
Nuclear	4.95	not considered
PV	9.49	3.75
Wind	5.61	2.7

Source: **A. Al-Qahtani et al.**, *Uncovering the true cost of hydrogen production routes using life cycle monetisation*, Applied Energy 2021/281; **G. Brandle et al.**, *Estimating Long-Term Global Supply Costs for Low-Carbon Hydrogen*, EWI Working Papers, Koeln 2020.

Under these circumstances, the main challenge in terms of continued utilisation of the LNG terminals in the EU will be their financing. In 2021, there were 25 operational LNG terminals, nine were under construction, and another 25 were being planned.[38] In Japan, there are as many as 31 terminals for LNG imports, accounting for 25% of the global regasification capacity, and one more is being constructed on the Shikoku coast.[39] Depending on whether SMR- or pyrolysis-based decarbonisation technologies are introduced to existing, constructed, or planned terminals, the total capital cost would be very significant (see Table 7).

TABLE 7: *Estimated investment costs in LNG terminals repurposing*

Total capital costs [EUR bln]	Existing + all planned EU	Existing + constructed EU	Existing + constructed JP
SMR with CCS	18.574	10.704	10.074
Plasma Pyrolysis	52.304	30.141	28.368
Future SMR with CCS	12.399	7.145	6.725
Future Plasma Pyrolysis	16.740	9.647	9.079

Source: own elaboration.

38 https://gie.eu/index.php/gie-publications/databases/lng-database; accessed 10.07.2021.

39 **IGU**, *World LNG Report*, IGU, Barcelona 2020, pp. 1–68.

The results imply that the investment necessary to repurpose a terminal would typically outgrow the investment made in the actual onshore terminals so far and would be several times higher than the costs of floating regasification terminals.[40] It also demonstrates that the investment costs for Japan alone would be no smaller than those calculated for all of the EU. The EU Member States and Japan should therefore choose terminals that will be vital to the local/regional security of supply. Determining the criteria for selecting such terminals would require a separate study that would factor in the infrastructure's contribution to the regional energy supply chains.

6. Calculation results – costs under scenario 2

Available biogas production and technologies that allow it to be upgraded to biomethane offer different unit costs. The highest are attributable to energy crops-based production and the lowest to plants using industrial waste (see Figure 1). Two different cost estimates are compared – one from IRENA and one from IEA.[41] From the perspective of this study, large plants would be preferable not only because of the unit cost of the output biomethane, but also because they would be capable of producing enough gas to fill large LNG carriers in a relatively short time. However, feedstock availability, alongside the necessary capital expenditures, would pose a major challenge, especially if imports from developing countries are considered.[42]

Biomethane production for exports is an attractive option for many developing economies, particularly those highly reliant on agricultural products that need to process the associated waste anyway. This option is already being explored in several countries. In this study, several potential candidates have been identified:

[40] **ERIA**, *Investment in LNG Supply Chain Infrastructure Estimation*, in: **T. Uemura**, **K. Ishigami** (eds.), *Formulating Policy Options for Promoting Natural Gas Utilization in the East Asia Summit Region Volume II: Supply Side Analysis*, Jakarta, pp. 67–80.

[41] **International Energy Agency**, *Outlook for biogas...*; **IRENA**, *Biogas for road vehicles: Technology brief, International Renewable Energy Agency*, Abu Dhabi 2018, p. 28.

[42] **T. Nevzorova**, **V. Kutcherov**, *Barriers to the wider implementation of biogas as a source of energy: A state-of-the-art review*, Energy Strategy Reviews 2019/26, pp. 1–12.

1. Nigeria – reported to have considerable biogas production potential.[43] It already has an LNG terminal in operation since 1989;[44]
2. Qatar – a major LNG exporter with significant liquefaction capacity readily available. The option of producing and exporting biomethane is already being discussed;[45]
3. Kenya – has had a programme of introducing biogas production across the country since 2009.[46] A feasibility study of a floating storage and regasification unit in Mombasa is already underway.[47] However, both the programme and the domestic biogas production are currently targeted at domestic production exclusively;
4. Democratic Republic of Congo – its biogas production potential is reported to be significant, although its current utilisation is symbolic.[48]

Of the four candidates chosen for the study, only the first two potentially hold the necessary capacity, know-how, and infrastructure to effectively respond to a call for renewable energy deliveries in the near future. The other two (Kenya and Democratic Republic of Kongo) are selected from many other potential candidates for which biogas production capability can be significant, and the delivery routes are similar to those beginning in Nigeria (i.e. from the western coast of Africa) and Qatar (from the Persian Gulf and eastern shores of Africa, via the Suez canal to Europe), respectively. It can be reasonably assumed that many of the analysed countries would be using similar feedstock for biomethane production, so the results of the analysis could provide a useful reference for other investors.

43 **F.O. Olanrewaju et al.**, *Bioenergy Potential in Nigeria*, Chemical Engineering Transactions 2019/74, pp 61–66.

44 https://www.nigerialng.com/Pages/index.aspx; accessed 19.08.2021.

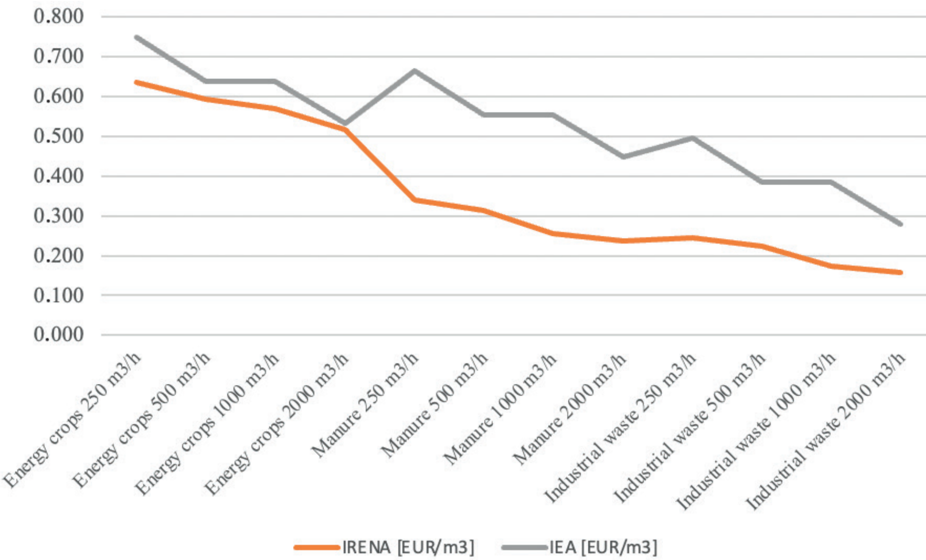
45 **F. Ferella**, **L.J.P. van der Broeke**, *An integrated approach for the generation of renewable energy from biomass and waste stream*s, “10th Conference on Sustainable Development of Energy, Water and Environment Systems”, Croatia 2015, pp. 1–18.

46 https://kenyabiogas.com/about/; accessed 19.08.2021.

47 **Algell J.**, *LNG in Kenya – SSPA supports the introduction of LNG into East Africa*, SSPA, Stockholm 2020, pp. 1–2.

48 **K. Kusakana**, *A Review of Energy in the Democratic Republic of Congo*, “ICDRE Conference”, Denmark 2016, pp. 1–10.

FIGURE 1: *Unit costs of biomethane production*



Source: own elaboration based on: **International Energy Agency**, *Outlook for biogas and biomethane*, IEA Publications, Paris 2020, p. 68; **IRENA**, *Biogas for road vehicles: Technology brief, International Renewable Energy Agency*, Abu Dhabi 2018, p. 28.

Rates for LNG chartering are charged per day and are typically dependent on the size of the ship and its propulsion mechanism.[49] To enable a reasonable comparison of the shipping costs, the following assumptions have been made:

- Ship size: 170,000 m^3 (for large LNG carriers), 20,000 m^3 (for small LNG carriers);
- Average vessel speed: 14 knots;
- Point of delivery: Gate Terminal in the Netherlands for the EU, Sodegaura Terminal for Japan;
- Sea distance (based on Sea Distance, 2020):
  - From Bonny terminal Nigeria: 13 days (to the EU), 32 days (to Japan);
  - From Mombasa port in Kenya: 19 days (to the EU, via Suez Canal), 21 days (to Japan);

[49] **H. Rogers**, *The LNG Shipping Forecast: costs rebounding, outlook uncertain*, Oxford Institute for Energy Studies. Energy Insight 2018/71, pp. 1–18.

- From Banana port in the Democratic Republic of Congo: 15 days (to the EU), 30 days (to Japan);
- From Doha port in Qatar: 19 days (to the EU, via Suez Canal), 20 days (to Japan).

- LNG vessel charter rates (based on Strantzali, Aravossis et al. 2018):
  - 35,000 USD/day for small LNG carriers;
  - 40,000 USD/day for large LNG carriers.

The abovementioned assumptions have been made to represent a "typical" case. The costs may be significantly lower for modern vessels with dual-fuel engines travelling at an average speed of 19 knots or higher[50], just as they can be much higher if extremely high short-term shipping rates are considered. Similarly, the distances will differ depending on the destination terminal chosen in the EU and Japan. Figure 2 below shows the calculated one-way charter costs from the terminals considered, excluding the Suez Canal transit costs and other associated costs, such as insurance and terminal fees.

The resulting figure for the chartering costs clearly shows that the countries on the eastern shores of Africa and those situated around the Persian Gulf could potentially be the best located for the first projects under EU-Japan cooperation in developing renewable gas production facilities (see Figure 2). The time (days) necessary to deliver cargo to either the Dutch or the Japanese LNG terminal from these locations are nearly the same.

For further cost analysis, additional assumptions had to be made:

- 1 m^3 of liquified natural gas equals 585 m^3 of regasified natural gas;[51]
- USD/EUR exchange rate has been set to 0.8475 (2019 average).

Transport costs can make up a large share of the total value of the cargo measured at cost, and this is quite naturally the case for small vessels. The calculated shares of charter costs in the entire delivery have been collected in Table 8 (for the EU) and Table 9 (for Japan) below. The analysis of the results leads to the conclusion that for truly large-scale trades, the impact of chartering rates on the entire transaction value may not be as significant as one might expect. This conclusion favours retaining a global market for gas and supports coordinated efforts of the largest importers to encourage broad participation in liquified gas trading.

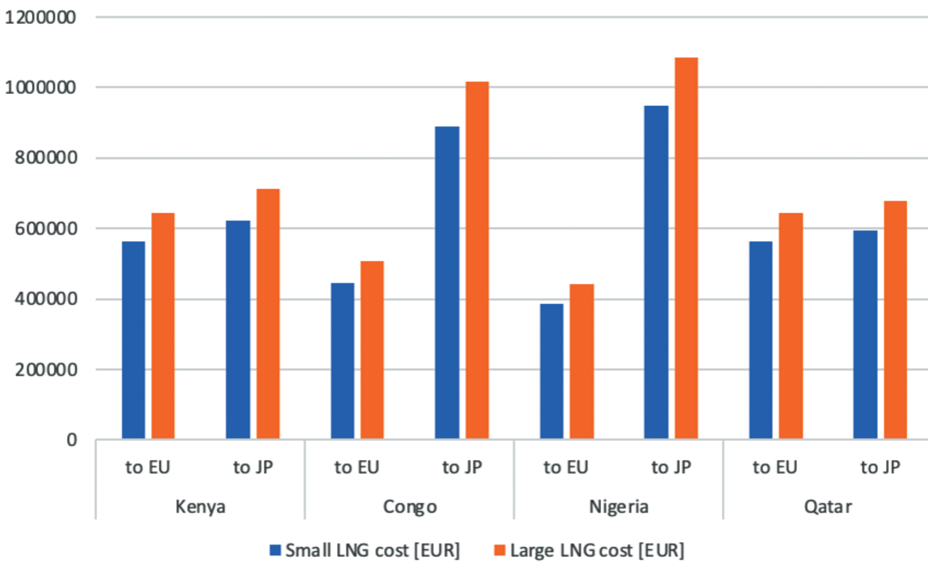
[50] *Ibidem*, pp. 1–18.

[51] **IGU**, *Natural Gas Conversion Pocketbook*, IGU, Barcelona 2012, pp. 1–40.

One other conclusion from the analysis of the charter costs is that their impact on the broader transaction costs may be limited, and ultimately, the competitive position of imported biomethane should be calculated against natural gas prices. In a competitive market for natural gas, with fewer and fewer gas quantities being sold under long-term contracts indexed against oil, these prices tend to be highly volatile. Hence, further calculations have been referenced against two assumed price levels recorded on the most liquid market for natural gas – the Dutch Title Transfer Facility, TTF (based on Thomson Reuter's Eikon, assumed conversion factor 1m^3 of natural gas = 0.011 MWh):

- TTF_{LO} – minimum front-month gas price reported for TTF between 2017 and 2019; TTF_{LO} = 0.166 EUR/m^3;
- TTF_{HI} – maximum front-month gas price reported for TTF between 2017 and 2019; TTF_{HI} = 0.189 EUR/m^3.

FIGURE 2: *LNG carrier chartering costs comparison – EU and Japan*



S o u r c e: own elaboration.

TABLE 8: *The share of chartering costs in LNG cargo costs – EU*

Transport cost share (IRENA)	Small LNG Kenya [%]	Large LNG Kenya [%]	Small LNG Congo [%]	Large LN Congo [%]	Small LNG Nigeria [%]	Large LNG Nigeria [%]	Small LNG Qatar [%]	Large LNG Qatar [%]
Energy crops 250 m^3/h	7	1	6	1	5	1	7	1
Energy crops 500 m^3/h	8	1	6	1	5	1	8	1
Energy crops 1000 m^3/h	8	1	6	1	5	1	8	1
Energy crops 2000 m^3/h	9	1	7	1	6	1	9	1
Manure 250 m^3/h	12	2	10	1	9	1	12	2
Manure 500 m^3/h	13	2	11	2	10	1	13	2
Manure 1000 m^3/h	16	2	13	2	11	2	16	2
Manure 2000 m^3/h	17	3	14	2	12	2	17	3
Industrial waste 250 m^3/h	16	3	13	2	12	2	16	3
Industrial waste 500 m^3/h	18	3	15	2	13	2	18	3
Industrial waste 1000 m^3/h	22	4	18	3	16	2	22	4
Industrial waste 2000 m^3/h	23	4	19	3	17	3	23	4

Transport cost share (IEA)	Small LNG Kenya [%]	Large LNG Kenya [%]	Small LNG Congo [%]	Large LNG Congo [%]	Small LNG Nigeria [%]	Large LNG Nigeria [%]	Small LNG Qatar [%]	Large LNG Qatar [%]
Energy crops 250 m^3/h	6	1	5	1	4	1	6	1
Energy crops 500 m^3/h	7	1	6	1	5	1	7	1
Energy crops 1000 m^3/h	7	1	6	1	5	1	7	1
Energy crops 2000 m^3/h	8	1	7	1	6	1	8	1
Manure 250 m^3/h	7	1	5	1	5	1	7	1
Manure 500 m^3/h	8	1	6	1	6	1	8	1
Manure 1000 m^3/h	8	1	6	1	6	1	8	1
Manure 2000 m^3/h	10	1	8	1	7	1	10	1
Industrial waste 250 m^3/h	9	1	7	1	6	1	9	1
Industrial waste 500 m^3/h	11	2	9	1	8	1	11	2
Industrial waste 1000 m^3/h	11	2	9	1	8	1	11	2
Industrial waste 2000 m^3/h	15	2	12	2	11	2	15	2

Source: own elaboration.

TABLE 9: *The share of chartering costs in LNG cargo costs – Japan*

Transport cost share (IRENA)	Small LNG Kenya [%]	Large LNG Kenya [%]	Small LNG Congo [%]	Large LNG Congo [%]	Small LNG Nigeria [%]	Large LNG Nigeria [%]	Small LNG Qatar [%]	Large LNG Qatar [%]
Energy crops 250 m^3/h	8	1	11	2	11	2	7	1
Energy crops 500 m^3/h	8	1	11	2	12	2	8	1
Energy crops 1000 m^3/h	9	1	12	2	13	2	8	1
Energy crops 2000 m^3/h	9	1	13	2	14	2	9	1
Manure 250 m^3/h	14	2	18	3	19	3	13	2
Manure 500 m^3/h	15	2	20	3	21	3	14	2
Manure 1000 m^3/h	17	3	23	4	24	4	17	3
Manure 2000 m^3/h	18	3	24	4	25	4	18	3
Industrial waste 250 m^3/h	18	3	24	4	25	4	17	3
Industrial waste 500 m^3/h	19	3	25	4	27	5	18	3
Industrial waste 1000 m^3/h	24	4	31	6	32	6	23	4
Industrial waste 2000 m^3/h	25	4	32	6	34	6	24	4

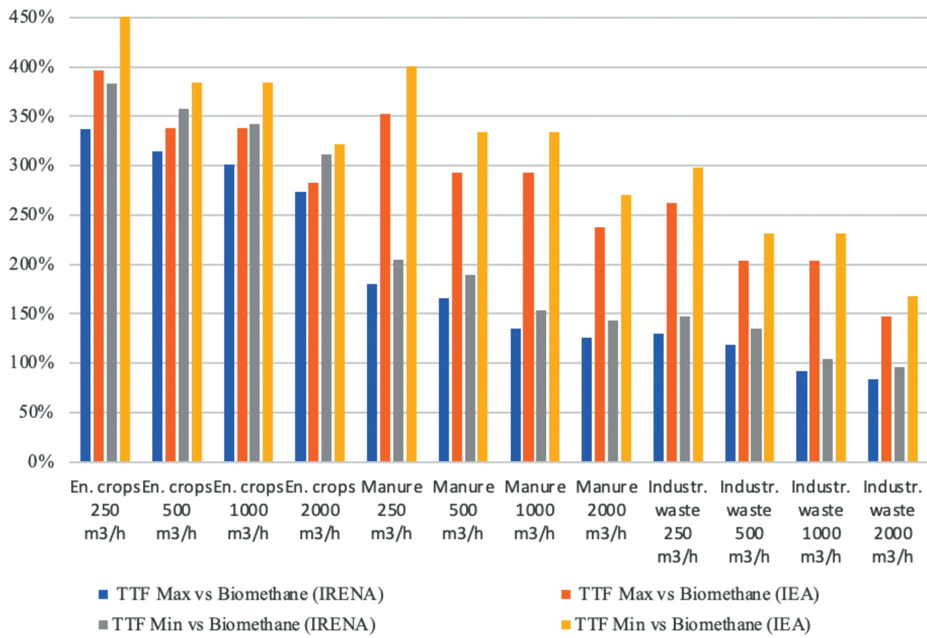
Transport cost share (IEA)	Small LNG Kenya [%]	Large LNG Kenya [%]	Small LNG Congo [%]	Large LNG Congo [%]	Small LNG Nigeria [%]	Large LNG Nigeria [%]	Small LNG Qatar [%]	Large LNG Qatar [%]
Energy crops 250 m^3/h	7	1	9	1	10	1	6	1
Energy crops 500 m^3/h	8	1	11	2	11	2	7	1
Energy crops 1000 m^3/h	8	1	11	2	11	2	7	1
Energy crops 2000 m^3/h	9	1	12	2	13	2	9	1
Manure 250 m^3/h	7	1	10	2	11	2	7	1
Manure 500 m^3/h	9	1	12	2	13	2	8	1
Manure 1000 m^3/h	9	1	12	2	13	2	8	1
Manure 2000 m^3/h	11	2	15	2	15	2	10	1
Industrial waste 250 m^3/h	10	1	13	2	14	2	9	1
Industrial waste 500 m^3/h	12	2	17	3	17	3	12	2
Industrial waste 1000 m^3/h	12	2	17	3	17	3	12	2
Industrial waste 2000 m^3/h	16	3	21	4	23	4	15	2

S o u r c e: own elaboration.

A monthly price reference has been suggested since month-ahead contracts are frequently traded even at less liquid hubs, making them a good reference for spot LNG deliveries (see, e.g., the Argus methodology[52]). The analysed period deliberately does not extend to more recent prices, which have seen exceptional fluctuations partially stemming from the COVID-19 pandemic.

The value of biomethane cargoes priced at their production costs quoted by IEA and IRENA has been compared to the value of these cargoes calculated using the TTF_{LO} and TTF_{HI} price reference. The results are presented in Figure 3 below.

FIGURE 3: *LNG cargo value comparison – biomethane vs natural gas*



S o u r c e: own elaboration.

The results confirm that even large, cost-efficient biomethane production would not be able to compete against natural gas without subsidies. Its competitive position would be even less favourable against pipeline-transported gas. It is difficult to envisage this price difference being counterbalanced by

[52] https://www.argusmedia.com/-/media/Files/methodology/argus-european-natural-gas.ashx; accessed 19.08.2021.

CO_2 emission allowance prices alone, especially since this price may only apply locally or regionally. Hence, some form of direct biomethane production subsidisation needs to be considered by the EU and Japanese authorities if they want sustainable energy imports to materialize. Further research could explore possible acceptable forms of investment and operational support offered outside the borders of these countries.

7. Conclusions

The study confirms that the existing infrastructure can be utilised in the future to facilitate the supply of renewable or low-carbon gases. Nonetheless, significant investment will be required to either facilitate the rollout of biomethane production or the production of carbon-free hydrogen. These costs will need to be borne by consumers, and given their potential size, it seems that coordination at the international level will be needed more than ever to ensure that decarbonisation of the economy happens at the desired speed. Japan and the EU's significance, combined LNG demand, as well as the shared commitment to climate protection, make them natural partners and potential frontrunners in fostering the decarbonisation of the global market.

Regardless of whether biomethane imports or natural gas processing at the receiving terminals are considered, a stable investment environment is an important precondition for the success or failure of these pathways. Capital expenditures underpinning both scenarios will be significant, and financing the LNG infrastructure is already a major challenge even without considering additional investment in underdeveloped technologies. Therefore, coordinated efforts are needed to ensure common procedures and taxonomy for determining and certifying commonly accepted forms of renewable and low-carbon energy carriers. Japan and the EU, which represent around half of the global demand for LNG, are well-positioned to establish and promote common standards for:

- certifying renewable characteristics of biomethane and defining the permissible feedstock types that ensure the gas produced meets agreed sustainability criteria;
- attesting technologies for natural gas processing to encourage R&D projects, possibly also through joint financing;
- metering and recording the associated emissions and carbon abatement efficiency to better reflect different technologies' contribution to tackling climate change and potentially improve the scope for renewable and low-carbon gas trading.

The two scenarios analysed in this study face two different challenges for the future. While natural gas-based hydrogen produced at the receiving terminals is expected to have a significant competitive advantage over hydrogen produced domestically through electrolysis, imported biomethane may be several times more expensive than the fossil gas it is to replace in the future. These results suggest that state aid aimed at enhancing the decarbonisation of the gas sector should focus on R&D and investment to support hydrogen production and CO_2 storage. Meanwhile, biomethane will likely require operational subsidies combined with increased costs for emitting greenhouse gases. Joint EU–Japan financing of R&D projects will, therefore, benefit hydrogen production and CO_2 storage, while common standards for biomethane production would improve its prospects for operational support.

Considering the EU and Japan's dedication to carbon neutrality, the synergy between the two solutions, whereby imported biomethane would be converted into hydrogen at negative CO_2 emissions, is worth studying. The results hint at the most favourable way of distributing state subsidies by policymakers wishing to foster new investment in decarbonising the gas sector. Joint initiatives for developing the underlying technologies would bring benefits to both the EU and Japan, even if shared subsidisation of production facilities in third countries proves to be politically and economically out of reach in the coming years.

The most important limitation that affects the presented study results is poor access to the most recent data on the actual cost per unit of decarbonised natural gas and on biomethane production. Many of the estimates used for this analysis are relatively outdated when considering the commercial interest in developing hydrogen production technologies. Additionally, the unit costs of biomethane as an arithmetical average can be inaccurate for specific appliances. It is also worth highlighting that some of the research on the subject thus far was not purely academic and hence might have been biased.

Further studies should focus on establishing a methodology for selecting the most critical terminal infrastructure across the EU and Japan that should be equipped with hydrogen production facilities first. International R&D cooperation and acceptable forms of joint projects certifying and subsidising biomethane produced outside the borders of the importing countries also require further analysis.

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Paweł LONT

SZANSE DLA WSPÓŁPRACY POMIĘDZY UE I JAPONIĄ W ZAKRESIE DEKARBONIZACJI GLOBALNEGO RYNKU LNG

Abstrakt

Przedmiot badań: Globalne ambicje klimatyczne zdają się pozostawać w sprzeczności z przyszłym wykorzystywaniem gazu ziemnego, jednak niezdolność rozwiniętych gospodarek do pełnej elektryfikacji zapotrzebowania na energię zmusza je do szukania innych metod dekarbonizacji nośników energii. W tym artykule zbadana została możliwość dalszego wykorzystywania gazu skroplonego jako źródła neutralnej klimatycznej energii dla państw Unii Europejskiej oraz Japonii, które obecnie odpowiadają za połowę światowego zapotrzebowania na skroplony gaz LNG.

Cel badawczy: Celem artykułu jest weryfikacja potencjalnych scenariuszy dla dalszego wykorzystania infrastruktury LNG w Unii Europejskiej i Japonii zarówno w procesie dekarbonizacji ich gospodarek, jak i w neutralnej klimatycznie przyszłości.
Metoda badawcza: Przeprowadzono kwerendę literatury traktującej o różnych technologiach wytwarzania lub importu neutralnych klimatycznie paliw gazowych celem identyfikacji metod dekarbonizacji sektora gazu ziemnego. Następnie przeprowadzona zostaje analiza SWOT dwóch najbardziej realistycznych scenariuszy celem prezentacji ich wad oraz zalet, jak też potencjalnych obszarów dla współpracy międzynarodowej pomiędzy krajami importującymi skroplony gaz. Na koniec zaprezentowane zostają szacunkowe koszty wynikające z dwóch analizowanych ścieżek rozwoju celem wskazania obszarów najtrudniejszych z perspektywy finansowania procesu dekarbonizacji.
Wyniki: Wyniki potwierdzają, że sukces analizowanych technologii konwersji gazu ziemnego uzależniony jest od innowacji technologicznych mogących obniżyć jednostkowy koszt pozyskiwanego w ten sposób wodoru, podczas gdy możliwość importu biometanu wymaga subsydiowania zagranicznych producentów, by zapewnić ich konkurencyjność. Autor wskazuje, że oba analizowane scenariusze dekarbonizacji sektora gazu ziemnego mogą okazać się komplementarne, jednak dostęp do finansowania może stanowić fundamentalną przeszkodę dla przyszłego wykorzystywania istniejącej infrastruktury LNG.

Słowa kluczowe: LNG, handel międzynarodowy, dekarbonizacja.