Securing & Greening Energy for Europe:

The Role of Terminal Operators

Presented by DNV & Frontier Economics

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i. Executive summary

Executive summary (1/2)

GLE has requested DNV and Frontier Economics to conduct a study on the potential of terminal operators to contribute to **securing and greening energy for Europe**. The analysis covers four central topics in Chapters 1 to 4:

- Chapter 1: The development of **EU markets** for natural, renewable and low-carbon gases and the relevance of **imports** and different long-distance transport modes;
- Chapter 2: The identification of **pathways** for imports and the analysis of indicative **costs** of imported renewable and low-carbon gases;
- Chapter 3: A discussion of the **techno-economic suitability** of terminals for the import of renewable and low-carbon gases; and
- Chapter 4: A comprehensive **assessment** of the pathways for the import of renewable and low-carbon gases against a wide set of criteria.

The key **conclusions** drawn in the study are summarised in the following.

1. *Valuable volumes:* Terminals enable the import of **renewable and low-carbon energy from overseas**. The need for imports of renewable and low-carbon energy has been demonstrated across various energy transition scenarios to meet the European needs for renewable and low-carbon energy, with imports via maritime transport complementing European production and pipeline imports. Maritime imports, in particular the import of hydrogen derivatives such as ammonia, can create more competitive and more liquid European markets.
2. *Building bridges:* Terminals provide **access to favourable renewable and low-carbon export locations** around the world. Many overseas locations, such as the USA, Chile, Morocco, and the UAE, can produce renewable and low-carbon energy at low Levelised Cost of Electricity (LCOE) and Levelised Cost of Hydrogen (LCOH). The maritime import route thus provides access to the lowest-cost production sites for renewable and low-carbon energy. We find that the pathways based on conventional LNG with CCUS come with the lowest maritime import costs. Most of the maritime import pathways with an upstream (overseas) production of hydrogen result in similar ranges of supply costs – there is no clear cost advantage for any particular pathway, so decisions on terminal transformation depend on a wider set of considerations, for example local/regional needs such as end-use application.
3. *Safety net:* Terminals contribute to the **security of supply** by providing import capacity with sourcing flexibility. They provide resilience to geopolitical developments and disruptions by enabling energy imports from many countries around the world, reducing dependence on individual countries or suppliers. Recent lessons from the energy crisis highlight the importance of terminals, as LNG terminals proved critical in securing energy supplies during a period of abrupt reductions in Russian pipeline gas imports.
4. *Waiting in the wings:* Terminals are **readily available** to import methane carriers (e.g. synthetic methane, biomethane) at any time and can be expanded or repurposed to import other carriers relatively quickly and at lower cost than greenfield infrastructure development. This flexibility accelerates emission reductions, especially for industrial clusters, and supports the development of a hydrogen-based infrastructure (possibly even before the development of the hydrogen backbone). Terminal sites and existing infrastructure have high value, including deep docks, space for further processing of hydrogen carriers, and access to connecting infrastructure. Other benefits include the storage potential of the terminals and synergies with cryogenic energy in processes such as CO_2 liquefaction.

Executive summary (2/2)

5. *Greening gradually:* Terminals allow for **different carrier and end-use pathways**, as well as other activities, and do not prescribe a single use case. The analysis shows that there is no "silver bullet" import pathway, but that different pathways have different strengths and weaknesses. In addition, they can perform non-import activities, act as carbon hubs or provide regional flexibility through truck/ship loading and virtual liquefaction. The flexibility of terminal operations is reflected in the diversity of projects recently designated as European Projects of Common Interest (PCIs) including Ammonia, LH2 and CO2 projects.
6. *Fit for many:* Terminals enable a green transition through **gradual emission reduction in light of varying needs across regions and time**. A diverse use of terminals across the EU (e.g. for hydrogen, e-methane, biomethane, ammonia, carbon) allows for a parallel ramp-up of a renewable economy while still maintaining security of supply for methane demand. In addition, terminals can facilitate local and regional emission reduction options by providing access to green carriers before (or while) alternative designated infrastructure (e.g. for hydrogen) is developed.

A set of **policy recommendations** (Chapter 5) has been identified to facilitate the contribution from terminal operators:

- **Terminal regulation:** In order to facilitate the contribution of terminal operators to the energy transition, regulators need to recognise the range of services that terminal operators can provide. This includes renewable and low-carbon energy import, CCUS and carbon handling, and other terminal services. Given that terminals are central to opening up new markets and value chains (such as CO_2), ensuring a stable policy environment, investment certainty and a level playing field across the markets is essential for competitive dynamics to enhance market efficiency. An appropriate, effective and timely implementation of the Green Deal and associated legislation, as well as the corresponding implementation of the member states (MS), should consider the operational variety of terminals and allow them to realise synergies of hybrid operation (i.e. accommodating multiple carriers or performing multiple services in the same terminal) by maintaining reasonable regulatory (unbundling) rules.

- **Policy environment for terminals:** Well-tailored policies can help overcome the co-ordinational hurdles across markets and stakeholders, and the teething troubles of an infant industry. Coordination of the European market needs to be managed across all dimensions of transformation, while respecting the specific needs of Member States and involving terminal operators and other stakeholders. To speed up the development, administration costs from all stakeholders should be kept at a minimum through low-threshold processes, e.g. in permitting, and harmonised standards, and technical development of less mature technologies should be facilitated.

- **Policies targeted at upstream supply value chain:** Maritime imports of renewable and low-carbon involve non-EU value chain elements in most cases. A high degree of international coordination, reasonable standardisation and certification schemes (e.g. guarantees of origin) are essential for the upstream value chain to be able to deliver what is needed in the downstream market. Unnecessary hurdles to international imports, like prevention of certification through the Union Database for Biofuels, need to be avoided. To maintain sourcing flexibility, a variety of strategic international partnerships can help to promote the range of dynamic sourcing and thus enable a more competitive sourcing environment.

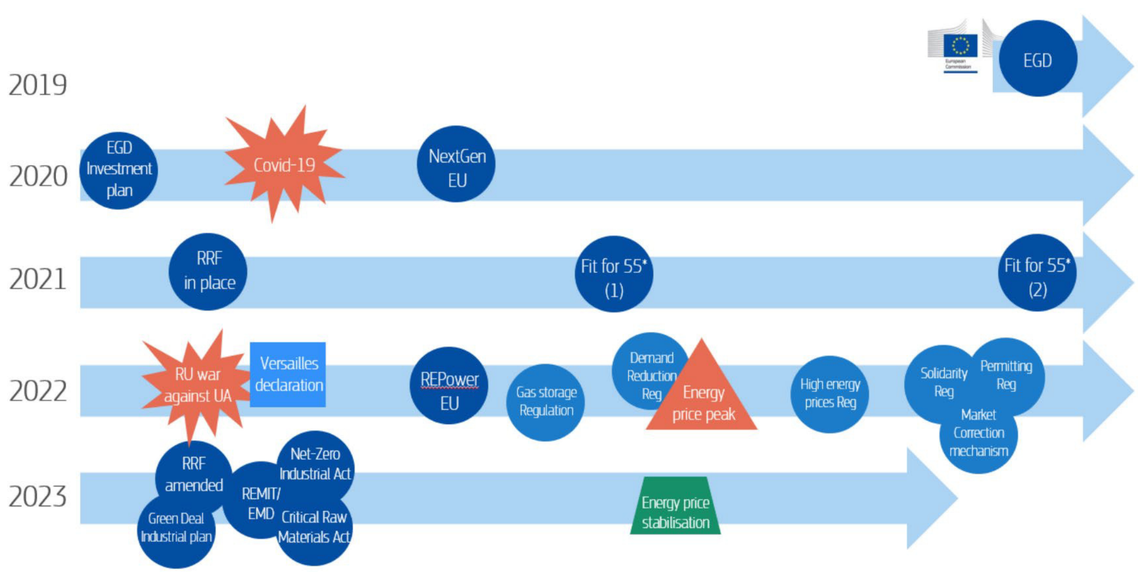
- **Policies targeted at downstream markets:** The transition to new services and carriers provided by the terminals depends on the transition of the downstream markets and technologies to renewable and low-carbon energy. It is important to ensure that end-use adjustments match the (regional) transition plans, so that downstream markets and terminals can co-move in their transition. An overly narrow policy focus also risks delaying efficiency gains in important markets, such as the CO_2 market for terminals acting as carbon hubs.

ii. Highlights of the report

Background: The EC has identified key challenges for the EU energy system and EU energy policy

Challenges and ambitions for EU energy supply

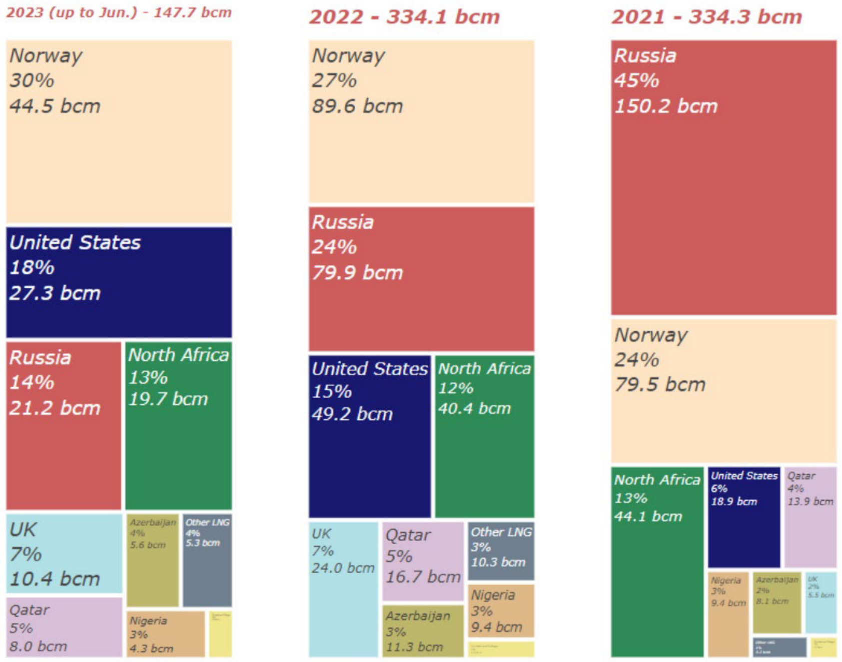
Timeline of EU energy policy



Source: Eighth report on the state of the energy union, 2023

Need to diversify gas imports

Composition of natural gas imports



Source: Eighth report on the state of the energy union, 2023

„Ensuring energy security, enhancing the EU's energy independence & completing the clean energy transition“

This study aims to analyse the market environment and technological capabilities to identify key contributions of terminals

Report Chapters

Market focus

1. EU gas market

Output: Determine and analyse the key drivers for importing renewable and low-carbon gases by ship or pipeline to meet overall EU import targets.

2. Pathway costs

Output: A comparison of costs for energy imports for different energy carriers, reflecting different maritime transport options.

Terminal focus

3. Terminal benefits

Output: Analyse and assess the contribution of the LNG regasification industry to different pathways for the import of low-carbon energy carriers

4. Assess pathways

Output: An assessment of the potential energy carrier import options (ammonia, LH2, synLNG, convLNG w CCUS) across various dimensions.

Policy focus

5. Policies

Output: Policy recommendations for the efficient import of renewable fuels and feedstocks, particularly on the back of the potential of LNG terminals to contribute to the targets.

Key contributions of terminals

Key contributions: Based on analyses of the market environment and terminal characteristics the study has identified **six key contributions** from terminals to the EU energy system challenges.

Valuable volumes
Enabling much needed renewable and low-carbon imports

Building bridges
Accessing favourable locations for renewables through worldwide sourcing

Safety net
Providing system resilience to disruptions through diversification of supply and back-up capacity

Waiting in the wings
Leveraging the value of readily available infrastructure for expanding to new carriers

Greening gradually
Growing progressively with transition

Fit for many
Allowing different import pathways and various other energy services

Icon sources credited in the annex.

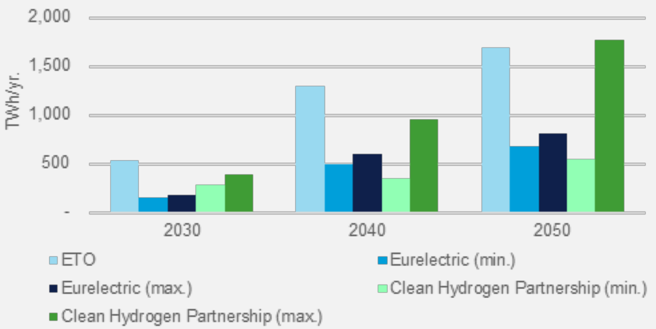
Terminals enable the import of climate-neutral energy, while providing sourcing flexibility and supply security

Terminals **enable the import** of **renewable and low-carbon energy** from overseas

Valuable volumes

- The **need for green energy imports is evident** in EU policy (RePowerEU 10 Mt import target) and all considered studies, albeit to varying extents.
- There is a **need for hydrogen (derivatives) imports via ship** to meet an expected increasing demand and to enhance supply diversity, supply flexibility, access to international supply, and increasing competition and liquidity on European markets. **Repurposed terminals could play a profound role in this.**

Hydrogen demand scenarios



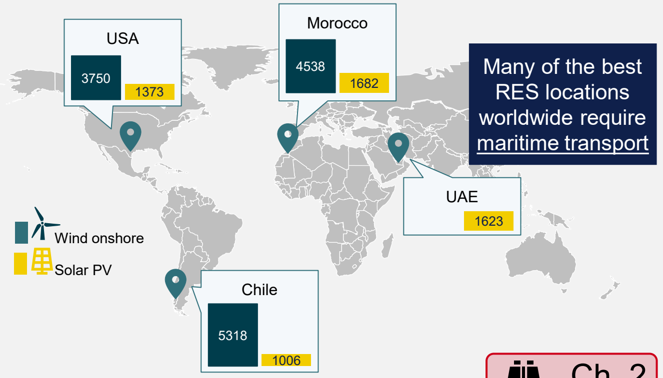
Ch. 1

Terminals provide access to **favourable renewable/low-carbon** export locations worldwide

Building bridges

- Numerous **overseas locations have favourable renewable energy conditions**, e.g. high full load hours and large potentials (volumes), unlocking relatively low LCOE and LCOH:
  - Exemplary locations situated in USA, Chile, Morocco, UAE.
- The characteristics of a maritime import terminal allows **access** to the most favourable locations worldwide.

Full load hours for exemplary sourcing countries



Source: Frontier Economics

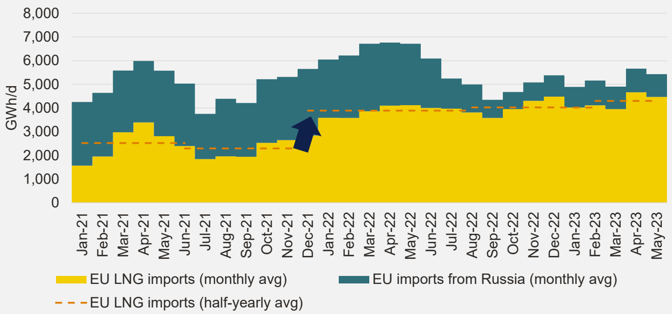
Ch. 2

Terminals guarantee security of supply through **providing import capacity with sourcing flexibility**

Safety net

- Terminals provide a high degree of **resilience to (geo-)political developments and disruptions** by allowing for sourcing flexibility across many countries worldwide, thus **decreasing dependence from single countries/suppliers.**
- Recent evidence during the energy crisis: LNG terminals have proven their **utmost importance for secure energy supplies**, with Russian pipeline gas imports falling abruptly and being replaced by an increase from LNG supplies.

Import/SoS contribution during EU energy crisis



Source: Frontier Economics

Ch. 1

frontier economics

DNV

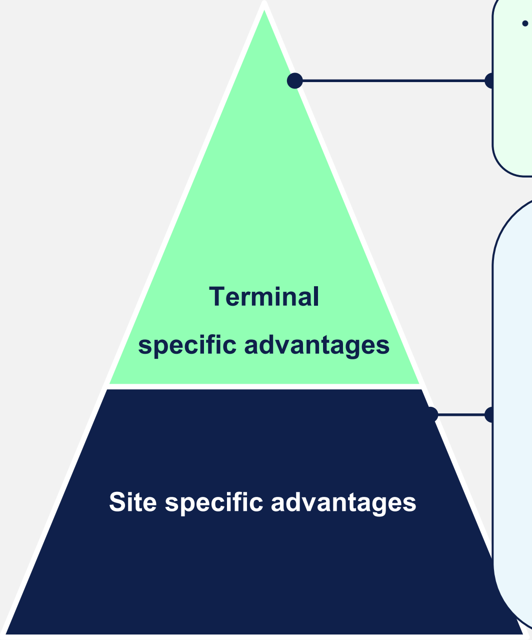
Terminals readily available to import methane carriers at any time; and well suited for future energy import

Terminals **readily available** to import (renewable) methane carriers at any time; and repurposable to import other carriers relatively quickly

Waiting in the wings

- Large scale hydrogen production and export projects are being planned and could become operational before a cross-European hydrogen backbone is in place. Import of energy through **terminals provides an alternative and non-discriminatory access route which can be available in a shorter timeframe**. Terminals can therefore accelerate decarbonization, in particular of industry clusters, and allow for the build out of a local hydrogen-based infrastructure which can later be connected to the backbone.
- **Flexibility of energy import** can contribute to robust multi-commodity energy supply to the EU (e.g. terminals that extend or convert part of their import capacity to other carriers).
- **High value of existing infrastructure and developed sites** such as a deep dock, space for further processing of a H2 carrier and access to connecting infrastructure.
- The **storage potential** of a terminal can be significant and can support the storage requirements of hydrogen infrastructure, especially in areas where access to salt-caverns is limited.
- Existing onshore terminals are **fit for import of e- and bio-methane** plus **repurposing for other carriers, especially for ammonia, which is feasible and cost effective** under some conditions.
- **Repurposing can reduce costs significantly** compared to greenfield (especially for ammonia).
- **Potential synergies with cryogenic energy** that can save costs and energy of other processes such as CO_2 liquefaction.
- **Potential to benefit from existing authorisation and local acceptance** with already existing upper-tier Seveso European guideline compliance.

Site and terminal specific benefits of existing terminals



- Cost reduction by re-using existing terminals or parts thereof (extent of reusability of asset components depending on which energy carrier is used)

- Availability of a site that is specifically intended for import of energy with access to infrastructure.
- Storage potential to support a stable energy supply chain.
- Space for energy import and further processing of carriers.
- Synergies with cryogenic energy and heat.
- Upper-tier Seveso establishments.

Source: DNV

Ch. 3

Icon sources credited in the annex.

Terminals provide operational flexibility by contributing to the transition through various activities

EU terminals enable a green transition through gradual emission reduction in light of varying needs across regions and points in time

Greening gradually

Fit for many

Terminals allow for **different carrier and end-use pathways,** not prescribed to a singular use case; moreover, they can also perform **other activities**

- ”**Smooth green supply transition**” by ability to serve remaining methane demand with climate neutral carrier while capacity is opening to new carriers, i.e. import terminals can already **provide market access to green carriers** while alternative designated infrastructure is still being developed.
- The terminal utilisation can **grow gradually with the green transition**. A diverse utilisation of terminals across the EU (e.g. H2, e-methane, ammonia, carbon) allows the **parallel ramp-up of a renewable economy** while maintaining security of natural gas supply.
- **Hybrid terminal use**: The same terminal can import multiple carriers if more than one storage tank is used.

The **terminal environment is granular and dispersed across Europe**, and allows for a diverse planning process for its green transition / its repurposing

The transition across terminals can vary in terms of
i.) **timing of repurposing**
ii.) **carrier** used / activity carried out (see “*Fit for many*) depending on local/regional needs and plans.

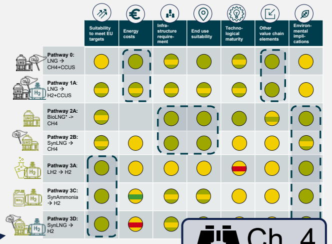
Ch. 1&3

European terminals and adapted PCI projects

Based on EC PCI map and annex EC proposal.

Source: Frontier Economics

- It is a key strength of terminals that they are not a uniform technology per se, but instead can **accommodate different carriers and can serve different purposes/activities,** and therefore provide **innate operational flexibility**.
- Terminals could **import various carriers**, enhancing diversification, depending on regional specificities (e.g. depending on local/regional end-use specificities at the terminal location; or eventual (local/regional) infra-structure development). **There is not one “silver bullet” import pathway**, but instead the pathways have different strengths and weaknesses.



Ch. 4

- Moreover, terminals are also fit for carrying out **non-import activities**: Either acting as a carbon hub or providing regional flexibilities through truck/ship loading/virtual liquefaction.
- This is confirmed through the **diversity of projects** that have recently been assigned as European projects of common interest (PCIs) that feature **ammonia**, **LH2** and **CO_2** projects. Terminals can serve diverse purposes according to specific and regional needs in the future and react dynamically to market developments.

Icon sources credited in the annex.

A set of policy recommendations has been identified to facilitate the contribution from terminal operators (1/2)

Terminal regulation	**Regulatory certainty**	• Regulation has been specified on EU level, but **implementation from MS/NRAs pending,** delaying eventual regulatory certainty. MS/NRAs could go beyond EU regulation in their implementation but should carefully assess reasons for doing so. • Ensure an **adequate, effective and timely implementation** of the Green Deal and finalise the remaining dossiers, including associated delegated and implementing acts. Integrate the role of terminals in the upcoming policy developments.
	Hydrogen terminal definition	• Regulations should allow for **multi-molecules/asset sites and hybrid operation** to enable synergies and economic benefits. • The current terminal definition covers the **importation of LH2 and ammonia**. To ensure a level-playing field across actors and activities and avoid regulatory inconsistencies, it requires a careful assessment whether **regulatory treatment should be applied to alternate import routes of H2** (and subsequent injection into the H2 grid) via other renewable/low-carbon carriers.
Ch. 5	**Terminal services**	• The regulatory rules need to reflect and allow (also in outstanding implementations of the MS) that terminals **will not act as import-only providers** in the future, but instead perform other energy system services (e.g. truck/ship (re)loading, virtual liquefaction) and **facilitate new markets and pathways** (e.g. acting as carbon transport hubs).
Policy environment for terminals	**Inconsistent planning**	• **Align and coordinate on national and EU legislation** on transformation pathways and timelines to take potential contributions of terminals into account, reflecting variation in pathways and timelines across MS and terminals. • **Involve terminal operators** in planning processes and include resilience planning in the emission reduction strategies.
	Immature technologies	• Measures to **support less mature technologies** across the value chain (e.g. financing of pilot projects, R&D, investments into innovation; potentially including hybrid terminals if there are non-private benefits such as increased SoS, emission reduction) to enable cost reduction despite learning spill-overs and realise public benefits (SoS, emission reduction).
	Regulatory readiness	• Unnecessary costs can e.g. be avoided by **maintaining scalability of import value chain.** This can be supported, for example, by conducting a revision of existing standards and requirements (e.g. rules for ammonia not fit for large scale imports with associated storage and further transport).
	Permission processes	• **Speed up, harmonise and facilitate** project licensing and permitting (also for imports of carriers other than LNG) for terminal operators and reduce bureaucratic efforts. Allow for "hybrid permitting", allowing for multiple molecules.

A set of policy recommendations has been identified to facilitate the contribution from terminal operators (2/2)

Upstream supply value chain / policy	**Carriers**	• Consider **different low-carbon energy carriers** across regulation and policies, including mechanisms such as H2Global (in its first window restricted to e-ammonia, e-methanol and e-kerosene) and European Hydrogen Bank.
	Internat. standards	• **International certificates** (e.g. globally coordinated **guarantee of origin** system), reasonable **certification requirements** (e.g. in the Union Database) and **standards** required to provide certainty to investors when taking investments at export/import terminals and to minimise compliance costs, in particular due to larger relevance of global value chain (e.g. rules for upstream emission reduction, certification).
	Sourcing flexibility	• Develop **strategic partnerships and cooperation** between the EU and multiple exporting countries / coordinate with international pillar of the European Hydrogen Bank. Support pilot / large-scale production projects in third countries, helping to kickstart and ramp up the renewable/low-carbon H2 (derivatives) import value chain.
Downstream markets / policy	**H2 end-use adjustments**	• In the short to mid-term, H2 injection should not be limited to an H2-only grid, but ramp-up can e.g. benefit from the option for **blending**, i.e. H2 injection in the methane grid in the ramp-up phase (depending on MS considered), **local/regional end use** near electrolysers and terminals, and **other means of transport** to end-use than pipelines.
	End-use planning	• Develop (national) **adoption roadmaps** that outline the gradual integration of renewable and low carbon energy imports into the EU and infrastructure planning with involvement of numerous stakeholders, including terminal operators.
	Narrow policy focus	• Consider **all potential future markets** to avoid stalling the development of certain markets due to lacking policy certainty, for example terminals could be an integral infrastructure element to future CO_2 flows – however, the **future developments of the CO_2 market** could be accelerated by providing clarity on policy and standards for private entities to take binding (investment) decisions.

Ch. 5

iii. Introduction to the project

The study provides insights into the usage of terminals for the imports of renewable & low-carbon gases

General

The European Commission has expressed interest in observing the measures that LNG terminal operators are taking to contribute to decarbonization, and how LNG terminals can be used for hydrogen and/or hydrogen derivatives. GLE developed regulatory, economic and technical cases around the decarbonization pathways for LNG terminals supported by Frontier Economics and DNV in 2020, for which:

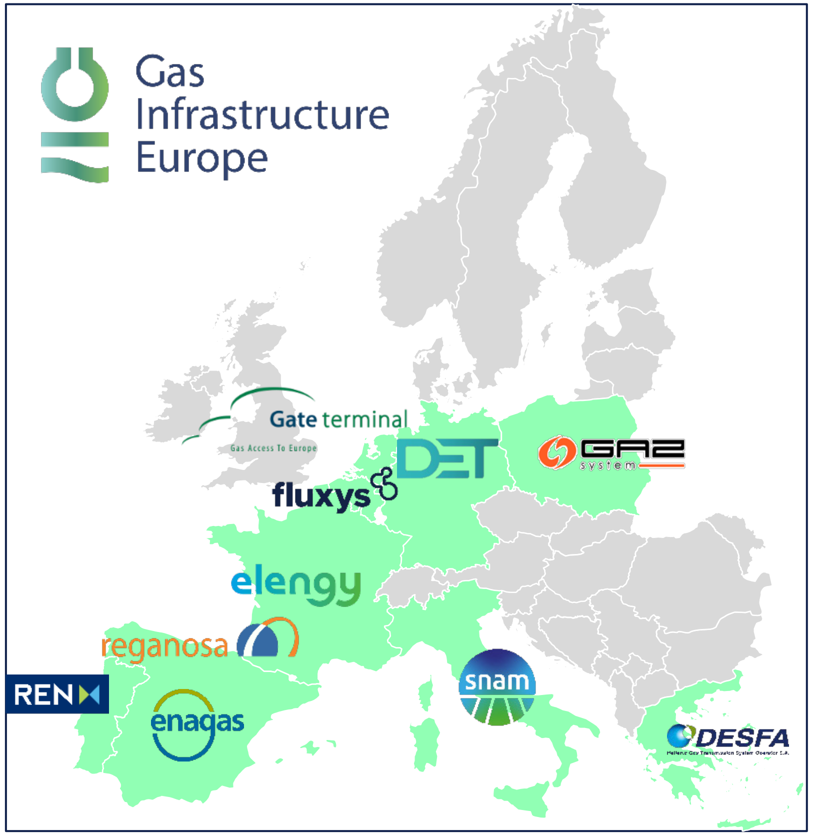
- Frontier Economics analysed barriers for four decarbonization pathways and identified policy measures to overcome these barriers.
- DNV analysed the future value chains from a techno-economic perspective, considering CAPEX, OPEX, efficiency and TRL.

This study

GLE has requested DNV and Frontier Economics to provide a report on the contribution of LNG terminals to greening and securing energy for Europe. The study aims at providing insights into potentials and possible scenarios regarding the usage of LNG terminals for imports of renewable and low-carbon gases, including hydrogen and its derivatives. The study is a collaborative effort between DNV and Frontier Economics. The lead author for Chapters 1 and 3 is DNV. The lead author for Chapters 2, 4 and 5 is Frontier Economics, with Chapter 5 building on the outcomes of the individual Chapters.

The analysis will showcase and help GLE understand the potential and long-term role of the terminals within the EU policy making framework. The funding members of this study are: DESFA, DET Energy, Dunkerque LNG, Elengy, Enagas, Fluxys, Gate Terminal, GAZ-SYSTEM, GNL Italia, GIE, REN Portugal, Reganosa (see Figure).

Funding Members of this study



The project results are presented in five Chapters

1. EU gas market

Objective: Determine and analyse the key drivers for importing hydrogen by ship or pipeline to meet overall EU import targets.

Approach: Present anticipated final energy demand for hydrogen and methane based on various studies and compare to existing and planned import capacities to determine likely utilization. Assess key drivers in the share of methane and hydrogen being imported by ship and pipeline.

2. Pathway costs

Objective: Evaluating cost estimates for import pathways that are considered to be most viable for the future use of maritime import infrastructure.

Approach:
Total costs of different import pathways evaluated by considering, local energy costs (electricity, hydrogen, methane) for representative export countries, costs for the transformation to derivatives and transport via ship, potentially followed by re-transformation.

3. Terminal benefits

Objective: Identifying benefits from repurposing existing terminals.

Approach: Identifying the benefits of existing terminals and their contribution to the future energy system by means of a techno-economic assessment. In the approach two categories are distinguished: site specific benefits and terminal specific benefits.

4. Assess pathways

Objective: Conduct holistic assessment of the potential maritime import pathways for renewable and low-carbon energy.

Approach: The following criteria are considered:
- Suitability to meet EU targets
- Energy costs
- Infrastructure requirements
- End use suitability
- Technological maturity
- Value chain requirements
- Environmental considerations

5. Policies

Objective: Develop policy recommendations for the efficient import of renewable and low-carbon gases.

Approach:
- Building on the results from the analysis on suitable energy import pathways and relevant future markets
- Consideration of barriers in policy and regulatory environment and links to upstream and downstream value chains and respective policies

We build on EU hydrogen targets, import pathways and demand insights (Chapters 1 and 2), and consider site- and terminal-specific benefits terminals could bring (Chapter 3). Further, we assess various maritime energy import pathways (Chapter 4). Finally, policy recommendations are given considering the output of previous Chapters (Chapter 5).

Market focus | **Terminal focus** | **Policy focus**

Chapter 1. Development of EU markets (volume) for natural, renewable and low-carbon gases and relevance of imports

DNV

1. EU Gas market Summary

- The EU currently depends on around 330 TWh of domestically produced hydrogen, mainly used as feedstock, and anticipates an increasing demand for hydrogen as an energy carrier (550-1,800 TWh by 2050). **Hydrogen (derivative) imports**, via a combination of pipeline and terminal import infrastructure, **are expected to be required to meet that increasing demand.**

- **EU terminals could be expanded with the advantages of leveraging existing sites** (see section 3) **or partially / fully repurposed** to accommodate hydrogen (and derivatives) imports in an optimised way, depending on the circumstances of each terminal.

- **A mix of pipeline and terminal import infrastructure** is most likely the best route to security of supply.

- Low-cost hydrogen and derivatives will be produced in nearby regions, with pipeline import opportunities, and **regions further afield, where shipping will be the only option.**

- Importing derivatives such as ammonia and methanol **by ship, for end use as ammonia/methanol, could be competitive with European production,** offering a more liquid market and lower prices for consumers.

- The **diversification of hydrogen transportation methods**, such as using ships and terminals, alongside a **broader range of suppliers**, is crucial to enhance the security of the EU's hydrogen supply, especially in the face of geopolitical uncertainties and changing energy landscapes.

Capacity

- **Currently,** there is likely no available capacity for converting terminals to hydrogen and its derivatives.
- **In the coming decades**, depending on the specific circumstances of individual terminals, some terminals will have the possibility for (partial) repurposing, while others could also expand to accommodate hydrogen and its derivatives.

International supply

- The EU is likely to **import hydrogen and derivatives** from a range of countries, via both pipelines and ships.
- **The EU has signed strategic partnerships** with counties that will require both pipeline and terminal import infrastructure.

Cost

- **Ships will transport hydrogen derivatives**, such as ammonia, likely for derivative end-use – in this case, imports transported by ship could be competitive with European production.
- **Terminals can play a key role** in supporting market liquidity and price competition, reducing costs for consumers.

Security of supply

- **Europe's diverse natural gas import infrastructure has been crucial** in ensuring physical supplies of gas in 2022-23, albeit at high prices, and the same will be true for hydrogen – a wider range of suppliers and flexible infrastructure will increase hydrogen security of supply.

1. **EU Gas market** Role of import terminals in the EU

In this analysis, we determine and analyse the key drivers for importing hydrogen by ship or pipeline to meet overall EU import targets (e.g. 10 Mt/yr. by 2030).

Approach:

European Methane Market

- Evaluate the final market for methane, including natural gas, biomethane and synthetic methane. Determine its size in Europe using DNV data (ETO) and information from public sources such as TYNDP and Eurelectric.

Methane (conventional, bio-LNG) imports into Europe

- Assess the expected role of methane imports through pipelines and terminals.

European Hydrogen Market

- Evaluate the final market for hydrogen (blue, green, etc.) as a commodity and measure its corresponding scale in Europe, utilizing DNV data (ETO), along with information from public sources such as TYNDP and Eurelectric.

Hydrogen imports into Europe

- Examine the anticipated role of hydrogen imports through pipelines and terminals.

Assessment of key drivers and conclusion on the future contribution of terminals to methane and hydrogen (derivative) import

In this task, we assess key drivers for importing methane and hydrogen (derivatives) by ship or by pipeline:

1. Informed by the market demand assessment and an internal DNV expert workshop, we assess the import of methane and hydrogen (derivatives) by pipeline and ship from the perspective of capacity, international supply, costs and price competition, and flexibility. The assessment is done in a qualitative and, where possible, quantitative way.
2. Taking this assessment of key drivers, and the previous assessments into account, we describe the future potential contribution of terminals to the import of methane and hydrogen (derivatives).

1. EU Gas market Natural gas outlook

In Europe, final energy demand is expected to decline significantly in the next 30 years due to increased energy efficiency and decarbonisation measures. Imports of natural gas are also expected to decline, although import flexibility and diversity will remain very important.

The approach of the market assessment primarily pivots around one critical component:

- Present and anticipated final energy demand for hydrogen and natural gas based on: TYNDP 2022 final scenarios, TYNDP 2024 input parameters, Eurelectric study (2023), and DNV Energy Transition Outlook (ETO) (2022).

The analysis of the natural gas market yields the following findings:

- **Future demand ranges:** Natural gas will continue to play an important role in the EU. Towards the 2040s its role will decrease. Studies estimate the **final** natural gas demand to be 960-2,500 TWh, 0-1,860 TWh, and 0-1,500 TWh in 2030, 2040, and 2050 respectively, compared to 3,300 TWh today.
- **Import demand ranges:** TYNDP 2022 also expects decreasing natural gas imports, accounting for 2,260-2,560 TWh (2030), 1,243-1,510 TWh (2040) and 0-260 TWh (2050) compared to about 3,200 TWh today.
- **Existing infrastructure is also required for synthetic methane and biomethane**, which are expected to become essential components of the decarbonised gas mix. The TYNDP 2022 findings reveal that biomethane and synthetic methane imports are projected to commence in 2040, amounting to 132 TWh and 73 TWh, respectively. These figures are expected to grow to 157 TWh and 310 TWh by 2050. However, the volumes are not expected to fully replace the anticipated decrease in natural gas volumes.
- Overall, even if gas volumes are expected to decline, existing import infrastructure can be expected to remain necessary in the following decades for the import of natural gas and the provision of important services such as supply diversity and flexibility (see EU Gas market Driver: Security of Supply).

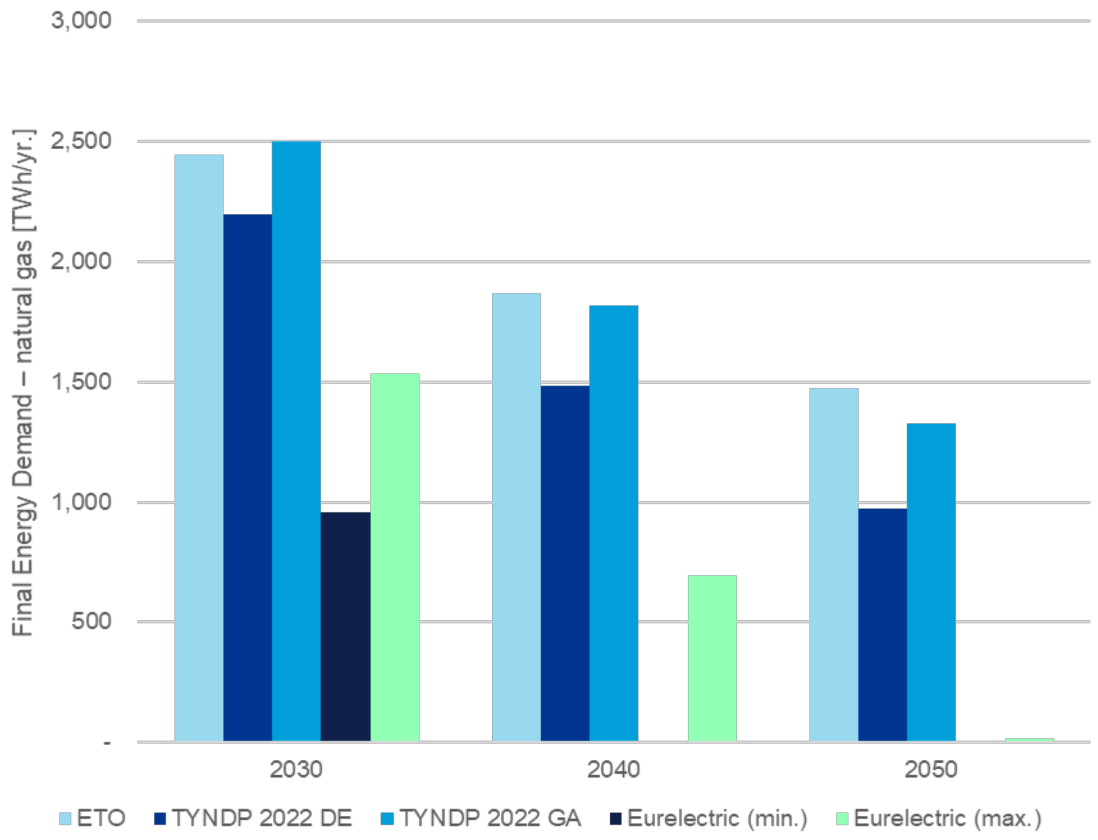


Figure: Final natural gas demand projections

Sources:
DNV. (2023). *Energy Transition Outlook 2023*. DNV.
Eurelectric. (2023). *Decarbonisation Speedways—Final report*. Eurelectric.
ENTSO-E, & ENTSO-G. (2022). *TYNDP 2022 Scenario Report: Download*. https://2022.entsos-tyndp-scenarios.eu/download/

1. EU Gas market Hydrogen demand outlook

The EU currently depends on around 330 TWh (10 Mt) of domestically produced hydrogen, mainly used as feedstock, and anticipates an increasing demand for hydrogen as an energy carrier. Hydrogen imports, even though uncertain in which form and transport mode, are expected to be required to meet that demand.

- **Future demand ranges** 330 TWh (current), 160 to 520 TWh (2030), 350 to 1,300 TWh (2040), and 550 to 1,800 TWh (2050). Some studies expect demand is largely met by domestic production (Clean Hydrogen Partnership (CHP) Base Supply Scenarios, ETO), while others project high import dependency (CHP - Increased Import Scenario, Eurelectric).

- **The need for hydrogen imports is evident in all studies, albeit to varying extents.** Discrepancies arise from factors such as the cost-effectiveness of importing certain portions of required hydrogen from North Africa and the Middle East compared to domestic production (based on the LCOH merit order) or the potential limitations on green power availability for hydrogen production, attributed to factors like permitting, NIMBY concerns, and others.

- Import ranges between 50-160 TWh (2030), 180-670 TWh (2040), and 130-1,230 TWh (2050). **Significant growth in hydrogen import by 2040 and 2050 remains uncertain in terms of form (pure or carrier) and transport mode (pipeline or ship).**
  - **ETO**: suggests relatively small quantities of pure hydrogen are imported via pipelines, while the import of pure hydrogen via ship is almost non-existent by 2030 and 2040 (e.g. North Africa, Ukraine). **Forecasts liquid ammonia as seaborne hydrogen** transport.
  - **TYNDP**: estimates import potential based on various sources (EHB, Moroccan hydrogen strategy, the PCI list of TYNDP22, and the IEA Global Hydrogen Review). **~40% of the hydrogen demand volume could be imported by ship** (pure or derivative). TYNDP2024 draft 'aligned National Trends' scenario provides information on hydrogen import until 2040 but does not distinguish between pipeline or ship. Assuming hydrogen will be transported by ship only in form of e-liquids and ammonia, while being transported by pipeline in its pure form, this would result in a **10-20% share of import by ship**.
  - **Clean Hydrogen Partnership:** envisions import of green and blue hydrogen from North Africa and the Middle East, primarily transported via ship, with ammonia as the preferred and cost-effective energy carrier (primary scenarios). Additional scenario based on REPowerEU envisions bulk of imported hydrogen arriving through pipelines from North Africa; North-west EU relies on ship-based hydrogen imports.
  - **Eurelectric:** does not further specify the import means (ship or pipeline) but generally assumes an **import dependency of 50%.**

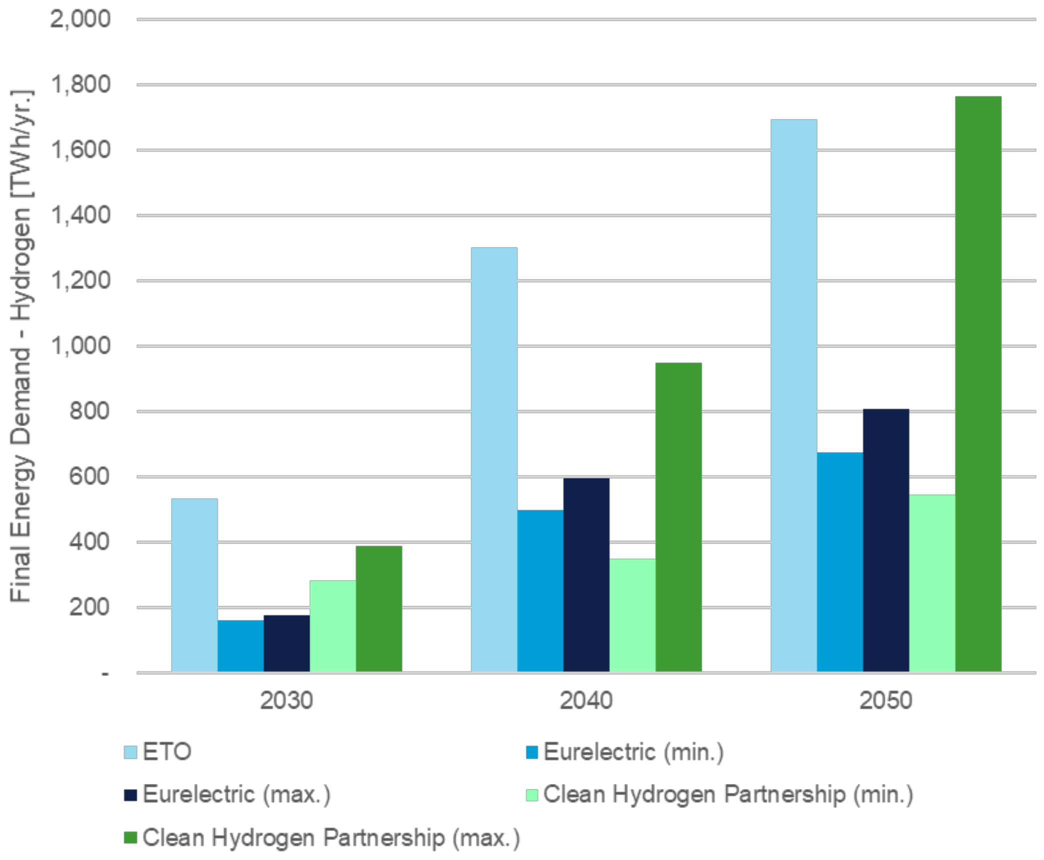


Figure: Development of final hydrogen demand.

Sources:
DNV. (2023). *Energy Transition Outlook 2023*. DNV.
Eurelectric. (2023). *Decarbonisation Speedways—Final report*. Eurelectric.
Clean Hydrogen Joint Undertaking. (2023). *Study on hydrogen in ports and industrial coastal areas. Report 1*. Publications Office of the EU

1. **EU Gas market** Infrastructure - LNG terminals (1/2)

EU's LNG import capacity is currently at about 2,100 TWh/yr. (180 bcm), with plans for 980 TWh (84 bcm) expansion; Germany, Italy, Greece, and Ireland lead capacity growth while Spain, France, and the Netherlands have the largest operational capacities.

In the following slide, we present an outlook for the import infrastructure, including currently installed and planned import facilities for methane, and hydrogen and its derivatives.

LNG import infrastructure:

- **The proportion of LNG imports in the overall natural gas importation has consistently risen in recent years.** It constituted approximately 20% of total imports in 2021, with its percentage increasing to 35% in 2022 and further to 41% in 2023 (as of 10 October).
- The **EU's operational import capacity for LNG** through onshore terminals and FSRUs currently stands at approximately 2,100 TWh/yr.
- **The largest operational import capacities** are located in Spain (700 TWh), France (380 TWh) and the Netherlands (230 TWh). Recently, Germany inaugurated two new LNG import terminals in Wilhelmshaven (90 TWh) and Lubmin (60 TWh), both of which are also equipped for hydrogen imports.
- **Planned capacity additions:** According to GIE, there are plans to add approximately 980 TWh import capacity per year (appr. +50%). Germany, Italy, Greece, and Ireland have the most substantial expansion plans for increasing LNG terminal capacity among all EU countries (combined 710 TWh or 2/3). The largest capacity additions for FSRUs are planned in Greece (150 TWh) Ireland (120 TWh) and Italy (120 TWh), while onshore capacity additions are mostly expected in Germany (200 TWh), Italy (90 TWh) and Estonia (80 TWh).

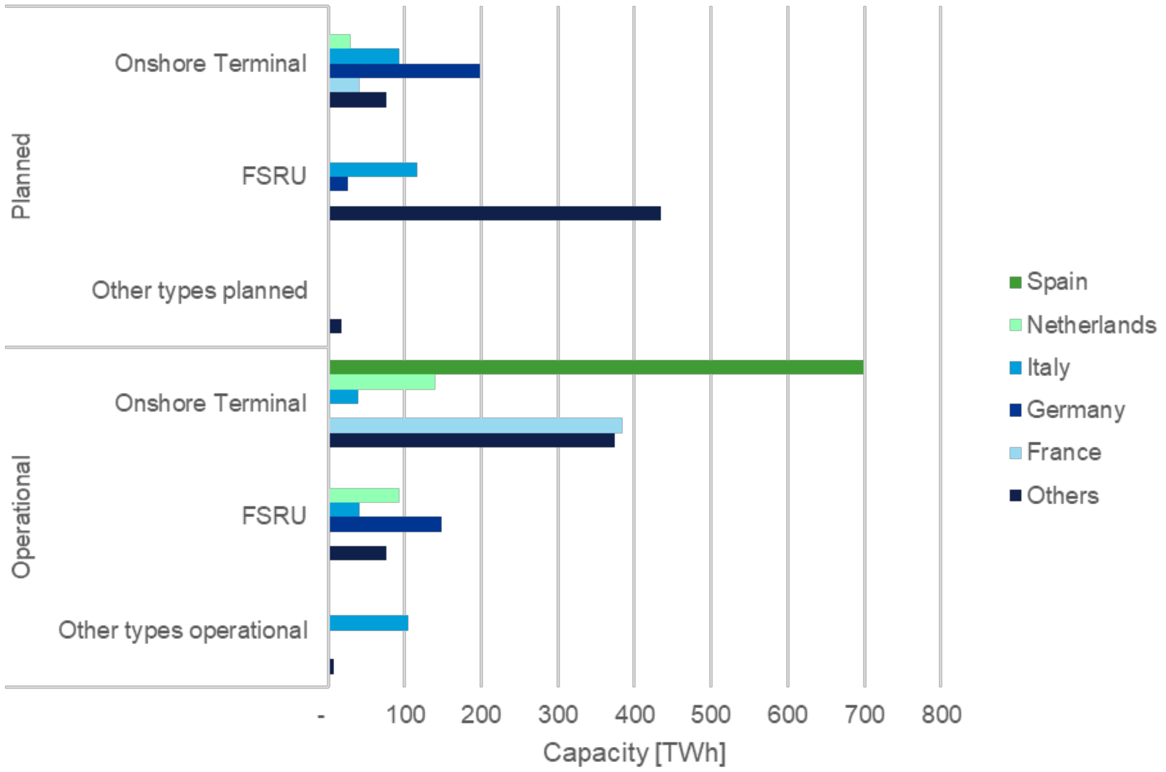


Figure: Overview of operational and planned LNG Import Capacity in EU-27 as of October '22 (Based on: GIE 2022). Note: (1) Operational capacities for Germany have been updated. (2) Other types planned: FRU + direct link to UGS; Other types operational: FSU + onshore regasification & offshore GBS (Gravity Based Structure)

*based on a gross calorific value of 11.63 kWh/(N)m3 at 0 degree C (Fluxys, link)

1. **EU Gas market** Infrastructure - LNG terminals (2/2)

LNG terminals play a crucial role in enhancing Europe's natural gas supply flexibility, as evidenced by the fluctuating demand patterns seen in 2021 and the substantial increase in LNG imports during 2022, driven by geopolitical tensions.

LNG terminals generally serve to enhance the flexibility of Europe's natural gas supply. This aspect is illustrated in the Figure on the right, particularly the LNG import data for 2021 prior to the Russian invasion of Ukraine.
In 2022, there was a significant rise in LNG imports, primarily driven by heightened geopolitical tensions. These imports played a crucial role in ensuring a steady supply of natural gas to Europe throughout the year. In 2023, while import volumes remained relatively stable, fluctuations in demand intensified, indicating a shift towards LNG serving a more flexible role, compared to its previous predominant use for baseload import requirements:

- The variation in import volumes during 2021 indicates fluctuations in demand, particularly with heightened demand at the beginning and end of the year coinciding with peak natural gas usage.
- In 2022, there was a notable surge in LNG imports, witnessing a significant 70% increase from appr. 900 TWh in 2021 to 1,500 TWh. Moreover, the fluctuations throughout the year were less significant. This trend underscores the sustained high demand for LNG during that year, prompted by shortages in pipeline imports resulting from geopolitical tensions, notably Russia’s aggression towards Ukraine. When comparing import volumes with LNG capacity, it is evident that terminals operated at nearly full capacity throughout the year, reaching 83% on average.
- Moving to 2023, import volumes remained relatively steady while terminal capacity expanded. Furthermore, fluctuations in imports intensified once more, with the standard deviation rising to 3.35 compared to 2.35 in 2022. This shift suggests that LNG is increasingly serving as a flexible resource once again.

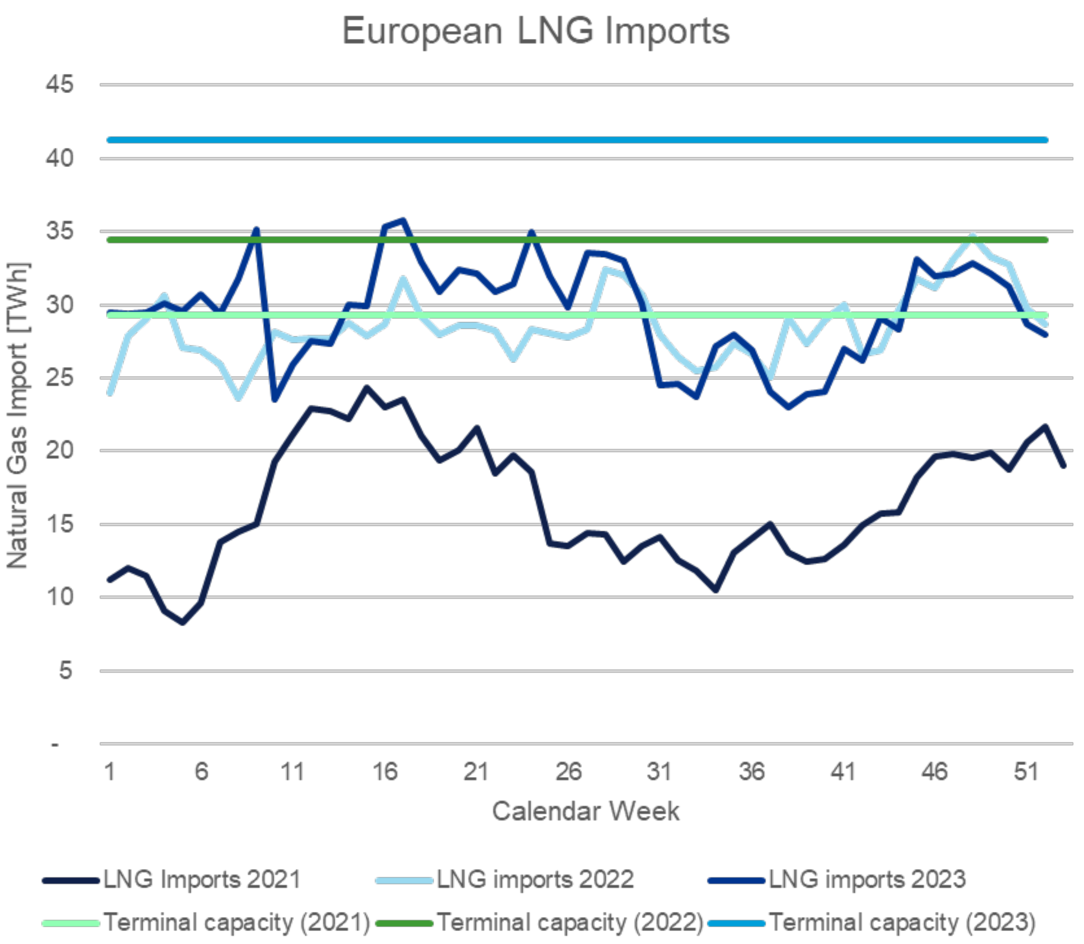


Figure: European LNG import development from 2021-2023 (author’s figure, Sources: Bruegel 2024, GIE 2022)

1. **EU Gas market** Methane import development

In 2022, the EU had 2,100 TWh/yr. of operational LNG import capacity, with plans to add 980 TWh/yr. Meanwhile, the natural gas pipeline capacity for importing from non-EU nations is expected to reach 3,150 TWh/yr. by 2030 but declines to 2,830 TWh/yr. in 2040.

LNG terminal operational and planned capacity

- As of 2022, the EU possesses operational import capacity for LNG through onshore terminals and Floating Storage and Regasification Units (FSRUs) at around **2,100 TWh/yr.**
- In terms of planned capacity additions, the GIE reports there are plans **to add approximately 980 TWh/yr.** of import capacity, which constitutes an increase of approximately 50%. Notable expansion plans are announced for Germany, Italy, Greece, and Ireland, accounting for a combined 710 TWh/yr (2/3 of total planned additions).
- By 2030, total terminal import capacity could account for up to 3,080 TWh/yr., out of which 930 TWh/yr. in the form of FSRUs. Note that FSRUs are assumed to stay operational until 2040, however, they may be relocated and therefore may not be available for transformation to hydrogen (derivative) import.

CH4 pipeline operational and planned capacity

- As of January 1, 2023, the operational transmission yearly capacity for importing natural gas to the European Union (EU) from non-EU nations, is approximately 2,810 TWh/yr. and is expected to increase by 2030 to 3,150 TWh/yr.
- In 2040, while import capacity is expected to increase from Turkmenistan and Israel, potential imports from Turkey, Norway, and Algeria are projected to decrease leading to a total import capacity of 2,830 TWh/yr in 2040 and 2050.

Overall import capacity is projected to increase from just over 5,000 TWh today to over 6,000 TWh in 2030, before falling slightly to just under 6,000 TWh in 2040.

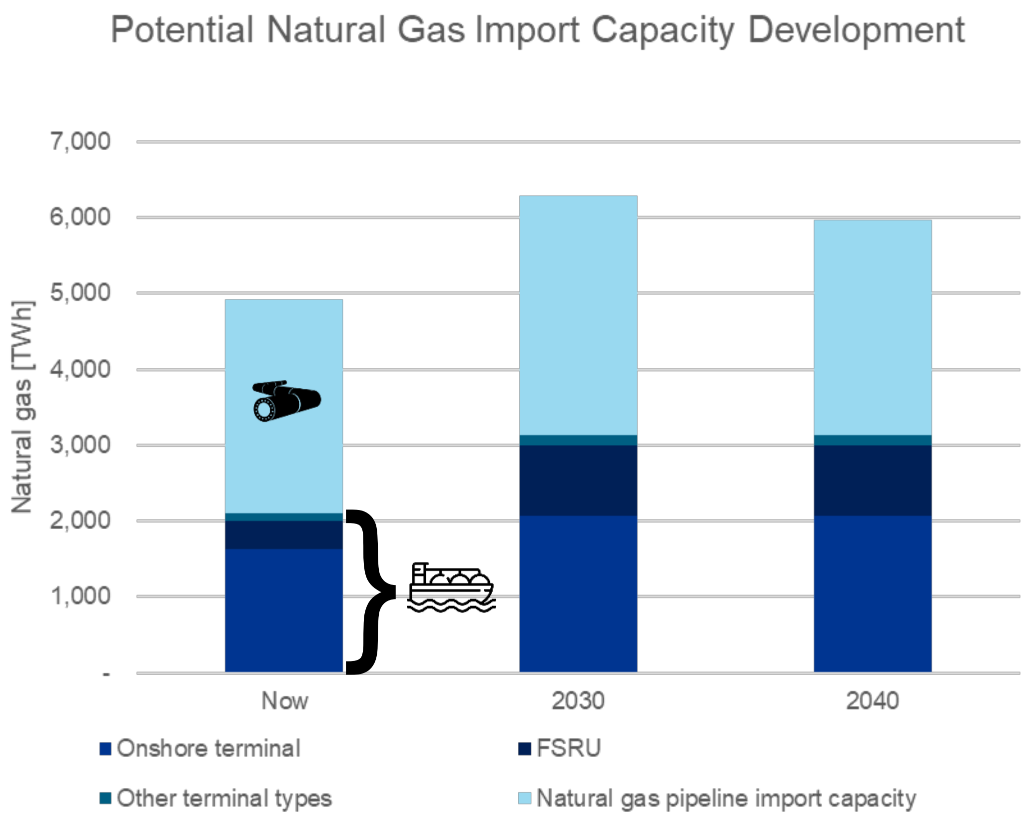


Figure: Natural Gas Import Development
* Assuming FSRU stays operational until 2040

1. **EU Gas market** Hydrogen import development

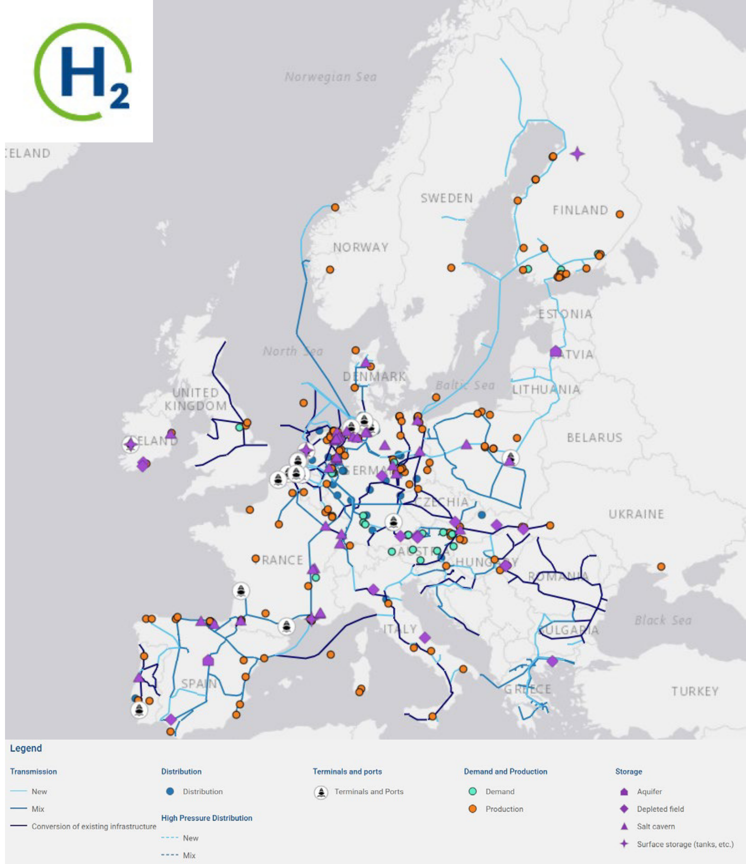
Announced planned hydrogen and derivative import capacities could allow the import of more than 710 TWh by 2030 with further significant increases by 2040. Planned terminal infrastructure for hydrogen derivatives excl. e-methane accounts for 90 TWh of import capacity while bio-/e-methane imports are limited by supply rather than import capacity.

Terminal operational and planned capacity

- The EU is poised for a **substantial surge in energy carrier imports**, including hydrogen, synthetic methane, ammonia, and methanol. We list key developments below, but the market is emerging, and this list is not exhaustive.
  - Overall, these developments signify a significant increase in energy carrier import capacities for the EU, with the **potential to import up to 90 TWh hydrogen derivatives excl. bio-/e-methane**, which includes 33 TWh of hydrogen from hydrogen-specific terminals, 54 TWh H2-eq. of ammonia, and 3 TWh H2-eq. of methanol.
  - Concerning dedicated hydrogen import, the Port of Amsterdam, SkyNRG and Zenith Energy Terminals assess the feasibility of a dedicated liquefied green hydrogen supply chain for Masdar-produced hydrogen to the port of Amsterdam (up to 33 TWh liquid hydrogen by 2030).
  - Ammonia imports in the EU are currently at 21 TWh, out of a total consumption of 98 TWh. Ambitious plans involve expanding ammonia import capacity to ~62 TWh (54 TWh of hydrogen equivalent, incl. cracking losses).
  - Methanol sees 80-86% of its 33-44 TWh demand imported into the EU (Eurostat). While terminal locations are known, specific import capacities are not disclosed. An estimate suggests planned additional methanol import capacity is 6 TWh, equivalent to 3 TWh of hydrogen (Guidehouse (2022)).
  - As for green gas, Wilhelmshaven, Germany, has announced an import terminal (TES), with a potential import capacity of 25-250 TWh of green gas, equivalent to 17-170 TWh of hydrogen. Given that green gas can be blended into existing infrastructure, import capacity is likely not the limiting factor, the supply of bio or e-LNG is.

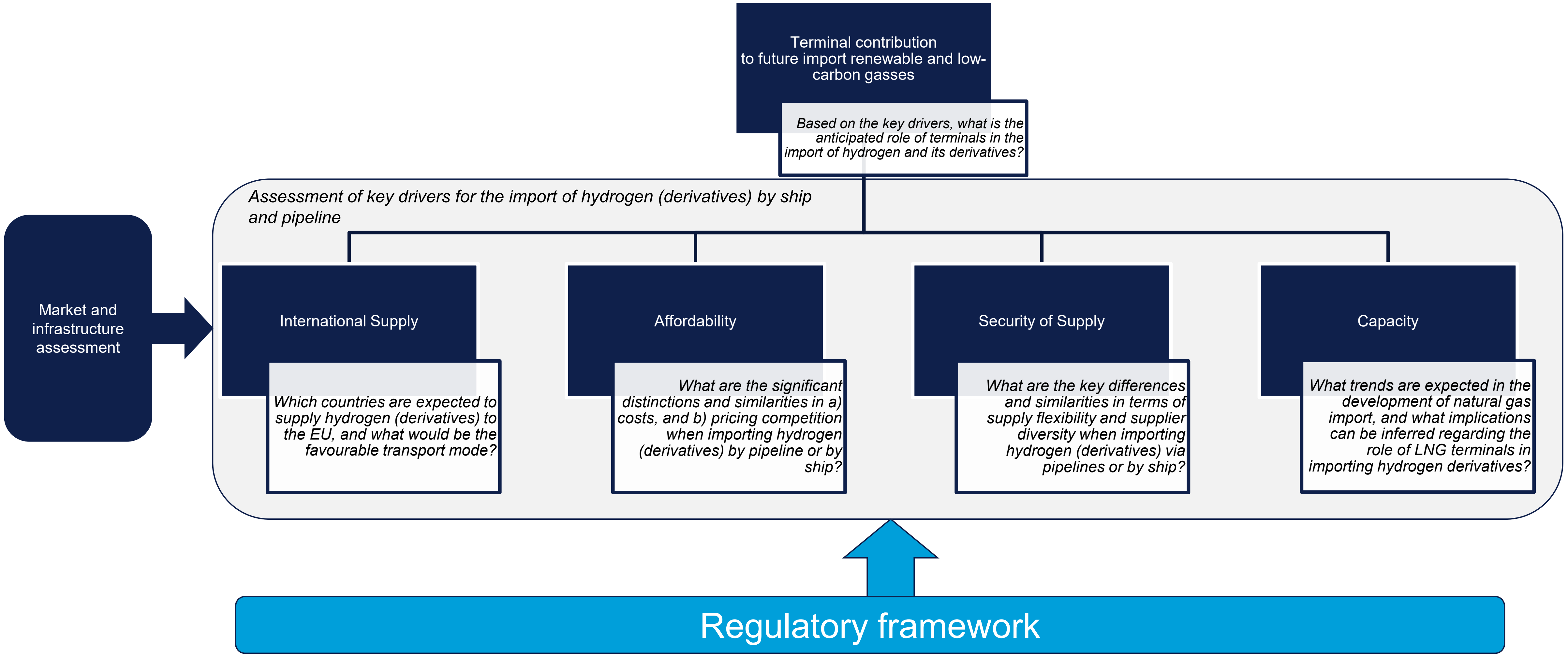
H2 pipeline planned capacity

- As of the present, there is no operational hydrogen import/export pipeline capacity in the EU.
  - By 2030, the European Hydrogen Backbone (EHB) envisions the establishment of three primary import/export connections: two pipelines running **from Ukraine to Croatia and Slovakia**, a pipeline **from Tunisia to Italy,** and one from **Norway to Northwest Europe**. This development is projected to result in a hydrogen import/export capacity ranging from 110-450 TWh/yr. Looking ahead to 2040, the EHB anticipates a significant increase to 1,400 TWh/yr.
  - Uncertainty surrounds a) hydrogen import transport mode (ship/pipeline) and energy carrier form, and b) realised pipeline/ (repurposed) terminal capacity. Plans for H2 and derivative terminal capacity additions are unknown beyond 2030.



Sources: Not exhaustive overview, H2 Infrastructure Map Europe. (2024). H2inframap.eu. https://www.h2inframap.eu/#map

1. EU Gas market Key drivers for the Import of Hydrogen (derivatives) by Ship and Pipeline



1. **EU Gas market** Driver International Supply

Which countries are expected to supply hydrogen (derivatives) to the EU, and what would be the favourable transport mode?

- ETO shows hydrogen transport will primarily rely on **pipelines for medium-distance** transportation within and between countries, with a limited role in intercontinental transport. Repurposing existing natural gas pipelines for hydrogen transport is cost-efficient, potentially accounting for over 50% of hydrogen pipelines globally and up to 80% in specific regions.

- Norway and North Africa have favourable renewable resources and potentially a low LCOH. Due to short distances, we expect to see hydrogen from both regions transported to the EU via pipelines. Ukraine is another potential source of hydrogen for the EU, and here pipelines would also be used.

- DNV's ETO expects that the Middle East and North Africa will be vital sources for Europe to enhance its hydrogen supply. The Clean Hydrogen Partnership states that Europe will have to increasingly rely on foreign suppliers, including North African and Middle Eastern regions, as well as more distant countries. Realizing this will require import infrastructure in Italy, Croatia, and Greece as early as 2030.

- Energy carrier transport via ships is preferable **for longer distances**, as we see in the natural gas sector for LNG. The economic feasibility of transporting hydrogen depends on factors like quantities, transported energy carrier and the mode of transport. According to the Royal Society (2020), shipping generally holds an advantage over pipeline transport for ammonia at distances just over 200 km and around 2,000 km for hydrogen. EHB (2021) identifies break-even distances for shipping as 800-3,200 km compared to a new 36" pipeline and 3,500 to beyond 6,000 km compared to a new 48" pipeline.*

- From other parts of the world, including for example the Middle East, Chile and North America, we expect a competitive LCOH, with the potential to transport hydrogen derivatives to the EU.

- Complementing the pipeline import aspect, DNV's ETO suggests that by 2050 up to 93 TWh out of a total 133 TWh of hydrogen will be imported by ship, primarily in the form of ammonia. Similarly, the Clean Hydrogen Partnership expects that most hydrogen is imported via ship in the form of ammonia or methanol.

Strategic partnerships established between the EU and potential exporting countries can impact where future hydrogen (derivatives) are produced and exported to the EU, and whether import by terminal or pipeline would be favourable:

- **Ukraine (2023)** – Strategic Partnership on Biomethane, Hydrogen, and other Synthetic Gases (link). For this case, energy carrier imports by pipeline is likely.
- **Namibia (2022)** - Strategic partnership on sustainable raw materials and renewable hydrogen (link). This would likely favour an import by ship/terminal.
- **Kazakhstan (2022)** – Strategic Partnership on raw materials, batteries and renewable hydrogen (link). Import by pipeline from Kazakhstan would be likely.
- **Canada (2021)** – Strategic Partnership on raw materials (link). An import by ship/terminal is logical considering geography.

National agreements are also being developed, and they offer potential for both pipeline and shipping imports. These agreements include:

- **Germany –** Several collaboration agreements outside of the EU, including with UK, Canada and Namibia.
- **Portugal** – Cooperation with Morocco to foster collaboration on green hydrogen developments (link).
- **Italy** – Private sector (Eni) collaboration with Saudi Arabia (Acwa Power).

* Note that the break-even point for transporting energy carriers increases significantly when considering repurposed pipelines. In that case, EHB(2021) indicates break-even distances beyond about 5,500 - 6,000 km across hydrogen transport in form of liquid hydrogen, LOHC, or ammonia.

1. EU Gas market Driver Affordability

What are the significant distinctions and similarities in a) costs, and b) pricing competition when importing hydrogen (derivatives) by pipeline or by ship?

Costs

- **For gaseous hydrogen import via pipelines, pre- and post-processing costs are negligible.** The main costs are compression and transport where the former accounts for up to 0.05 EUR/kg H2/1000 km, while new pipeline costs account for roughly 0.1 – 0.25 EUR/kg H2/1000 km (IEA 2022).* Compared to transport by ships, **the pre-and post-processing costs can be higher than the transport costs** since hydrogen would need to be converted (to liquid H2, or derivatives) and reconverted.**

- The costs associated with **storing hydrogen** are commonly incorporated into terminal costs, with additional costs arising in the context of required storage for pipeline transport. Specifically, for salt caverns, aquifers, or depleted gas fields, these additional storage costs range from 0.27 EUR/kg to 0.84 EUR/kg (DNV 2019, UK Government 2023).

- Lower costs per transport mode also depend on the specific end-use. **For the end-use of gaseous hydrogen**, numerous studies (including by DNV, Agora Energiewende, Aurora Energy Research) find that the lower LCOH in regions such as North Africa is likely to mean that **hydrogen transported by pipeline to Europe** is more cost-competitive with European production. For the **end-use of hydrogen in the form of derivatives such as ammonia,** derivatives produced in non-European regions with a low LCOH can be competitive with domestic hydrogen derivative production and can be expected to be transported and imported via ships.

Price competition

- **Diverse supplier options:** Terminals allow for more diverse sourcing options for energy carriers. When using pipelines, one is often limited to sources located along the pipeline route. In contrast, terminals can receive shipments from various suppliers around the world, which can lead to **increased competition and potentially better pricing.**

- **Competitive global market:** Energy carriers imported via terminals often tap into the global market. This means that **prices are influenced by global supply** and demand dynamics, as well as international market forces. This can **introduce a level of competition that might not be present in regional pipeline systems,** where pricing is more localized. On the downside, while the global market can introduce price competition, it can also subject energy carriers to global supply and demand fluctuations.

- **Price transparency:** Importing energy carriers via terminals can enhance price transparency and market liquidity. Pricing information for globally traded commodities, like LNG, is often readily available and easily accessible, which **can empower buyers and sellers to negotiate better deals.**

- **On short distances, e.g. from Northern Africa, imports of gaseous hydrogen via pipelines are more competitive than ship transport.**
- **However, ship transport is the preferred option for long distances and enables access to markets which are not accessible by pipelines.**
- **Also, import terminals can play a key role in supporting price competition.**

* depending on pipeline size and utilization rate
** In the case of ammonia for example, post-processing costs (reconversion to hydrogen) alone make up for one-third of the total transport costs (about 0.7 EUR/kg out of 2.2-2.3 EUR/kg).

DNV

1. EU Gas market Driver Security of Supply

What are the key differences and similarities in terms of supply flexibility and supplier diversity when importing hydrogen (derivatives) via pipelines or by ship?

Supply Diversity

- **More flexible hydrogen transportation options will be needed to fill the gap and ensure that hydrogen can reach the EU from the widest range of countries.** The transport of hydrogen carriers by ship offers more supply diversity, including from regions further afield, as is the case for LNG.
- Pipelines provide continuous energy supply, meeting essential needs for many users while being typically backed by significant geological storage for seasonal gas demand. However, pipelines may not be feasible for future distant imports into the EU. Terminals also ensure continuous supply when linked to extensive storage facilities.
- Both pipelines and terminals typically allow a wide range of third parties to access them through regulated third-party access (TPA). However, terminals, due to their technical characteristics, can be physically accessed by a more diverse group of suppliers, not restricted to specific feed-in points.

Supply Flexibility

- Supply flexibility in terms of the ability to alter supplier composition periodically has not historically attracted a market premium. However, since the Russian aggression towards Ukraine and its repercussions on the European Union's energy landscape, the value of being able to switch gas suppliers quickly has become more apparent.
- In light of this development, countries contemplate how to appropriately recognize this value. Notably, the Netherlands has implemented a groundbreaking measure: LNG terminals now benefit from a 20% discount on gas transport tariffs, bolstering supply flexibility and reducing costs for terminal operators beginning in 2024.

Supply Security

- **Failure of infrastructure of exporting infrastructure partners has a lower impact on import terminals,** given that alternative exporters can be available.
- **Geopolitical events affecting one country or region are less critical,** given that supplies can be increased from alternative countries and regions.
- **The importance of supply security offered by terminals is now being acknowledged.** For instance, in the Netherlands, LNG terminals will receive their first-ever discount (20%) on the gas transport tariff, starting in 2024.
- **The same picture will be true for hydrogen** – a wider range of suppliers and flexible infrastructure will increase hydrogen security of supply.

1. **EU Gas market** Driver Capacity

What trends are expected in the development of natural gas import, and what implications can be inferred regarding the role of LNG terminals in importing hydrogen derivatives?

Natural gas import infrastructure – LNG terminals and pipelines that do not originate in Russia – currently has a relatively high utilisation rate with likely no room for imports of hydrogen and derivatives. Spare capacity might potentially emerge towards the 2040s, depending on the specific circumstances of individual terminals. Meanwhile, terminals could consider expansion to accommodate hydrogen and its derivatives.

Current

Relatively high utilisation of capacity

- In 2022, the EU had an LNG import capacity of 2,100, including the new FSRUs that started up in 2022. Total LNG imports were 1,500 TWh which is equivalent to almost full utilization considering seasonal variations, with utilization up to 90% during peak demand periods (e.g., winter 2022).
- Pipeline imports that did not originate in Russia were also high, at 2,000 TWh overall, up from 1,700 TWh in 2021. Capacity utilisation from Norwegian pipelines averaged 85%, and from Algerian pipelines 74% - the main limiting factor being gas production levels in these countries. The Libyan pipeline to Italy (Green Stream) averages a low 17%.
- **Currently, there is likely no available terminal capacity for converting to hydrogen and its derivatives under the existing conditions.**

2030s

Possible opportunities for expansion/(partial) repurposing

In 2030, Europe's non-Russian gas import infrastructure is set to increase, including new FSRUs and onshore LNG terminals reaching 3,000 TWh installed capacity in total. Also, pipeline import capacity is expected to increase, resulting in a combined non-Russian pipeline capacity of 3,200 TWh.

- While Europe's total gas import demand is projected to decrease to 2,300-2,600 TWh in 2030, LNG terminal capacity is expected to remain largely utilized to serve supply diversity and supply flexibility.
- **In some cases, spare capacity for onshore terminals may become available** depending on individual terminals' circumstances. Simultaneously, some onshore terminals may expand to support the handling of hydrogen and its derivatives
- **FSRUs** can be relocated to other regions, leaving the jetty/installations accessible for modification for the import of hydrogen and its derivatives, if necessary.

2040s

More opportunities for expansion/(partial) repurposing may become available

- Plans for capacity expansions by 2040, be it by pipeline or by terminal, are naturally not as detailed as for 2030.
- By 2040, natural gas import volumes are expected to further decrease while biomethane and synthetic methane imports increase. The overall import volumes are expected to account for 1,400-1,500 TWh.
- At this point, there is a **possibility that the trend in the 2030s continues with extra terminal capacity being repurposed and terminal capacity expanding** for hydrogen and its derivatives.

DNV

1. **EU Gas market** Challenges in practice

Although, over time, there may be some potential to expand or repurpose existing gas import infrastructure to hydrogen and derivative imports, there are several challenges to achieving this in practice, including timing, types of energy carrier, end-user demand and skills and supply chain.

Timing challenge	• Capacity can have a challenge concerning timing if the development of hydrogen (derivative) **production capacities in exporting countries moves at a different pace** from the development of import/export infrastructure. There may be challenges in the timing of projects to repurpose terminals and pipelines, with unused capacity at the start. • **Hybrid terminals** (see chapter 3), which involve progressively repurposing components of existing terminals, have the potential to swiftly adjust to timing challenges and emerging market trends while concurrently maintaining (partial) engagement in the LNG import sector. • The fulfilment of security of supply, with a focus on supply diversity and flexibility, can result in LNG terminals required to remain available in the longer term.
Energy carrier challenge	• There are uncertainties e.g., material and component suitability and safety and security implications, with regard to the energy carrier through which hydrogen is imported (see chapter 3). Also, the significant growth in hydrogen imports by 2040 and 2050 remains uncertain in terms of form (pure or carrier) and transport mode (pipeline or ship).
Bottom-up driver	• The expansion of actual **import capacity is more likely to be influenced by bottom-up developments,** including the difficulties of agreeing long-term contracts for major supply and offtake prior to the construction of any new import infrastructure, rather than being primarily guided by EU-imposed top-down targets. Bottom-up development may also originate from Port Authorities that have established MoUs with exporting countries.
End-user challenge	• The question as to whether import terminals or pipelines are required also partly **depends on the end-user.** Gaseous hydrogen to meet end-uses such as high-temperature industrial heat may be more likely to arrive via pipelines, and derivatives for end-use in the maritime and aviation sectors may be more likely to arrive via ship. To the extent that LH2 becomes viable as a shipping option, it would also be straightforward for terminals to inject gaseous hydrogen in national backbone pipelines.
Skills and supply chain challenge	• The ability to import hydrogen (and its derivatives) adequately also relies on **proficient personnel and capable companies.** Transporting hydrogen derivatives at a large scale represents a novel sector for energy firms, traders, and logistics enterprises.

Chapter 2. Pathways for import of renewable and low-carbon gases and indicative costs

frontier economics

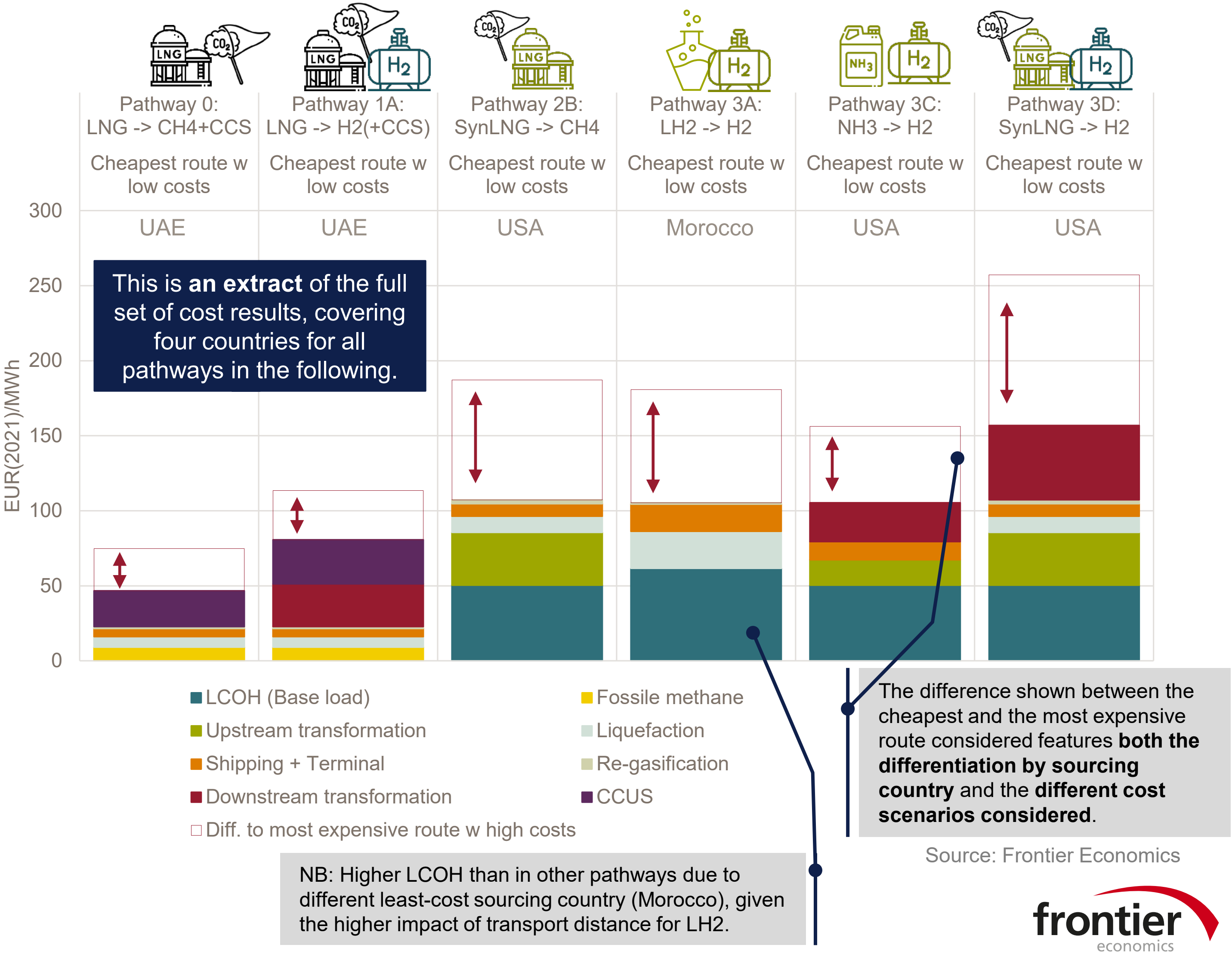
2. Pathway costs 2040 Import pathway cost summary

Decarbonising fuels can become relatively affordable in **2040** - for different sourcing countries and different pathways (“*fit for many*”)

- We estimate the **future energy supply costs for imports of different energy carrier pathways in 2040** by ship, utilising terminals to the EU.
- We find that most **upstream hydrogen pathways result in similar supply cost ranges** (pathways 2-3, with the exception of 3D) – there is no clear cost advantage for a specific pathway, so terminal transformation decisions depend on wider set of considerations, for example local/regional needs (such as the end use case).
- A **downstream transformation of SynLNG to H2 is very costly****. The pathway featuring SynLNG as a H2 carrier is the most expensive import pathway.
- The pathways relying on **conventional LNG with CCS** generally come with **lowest import costs**, associated with uncertainty around natural gas prices and carbon capture costs.
- It should be noted that the **willingness-to-pay for the carbon-neutral pathways depends on the end-use**:
  - As a reference point for the willingness-to-pay for carbon-neutral H2 in end-use, the cost of grey H2 with methane+ATR from UAE/USA without CCUS plus a RED III penalty (here: 450 EUR/t CO2) would result in **164-197 EUR/MWh**.
  - For CH4 in end-use, the equivalent consideration would be at **100-125 EUR/MWh**.

* Transformation losses are counted towards the associated technology.

** The efficiency losses incurred in the transformation of SynLNG to H2 are more costly than the same process for fossil LNG due to higher underlying costs for the commodity.



Source: Frontier Economics

Icon sources credited in the annex.

2. Pathway costs 2040 Approach to cost estimation

We focus on a number of pathways, and combine country-specific optimised LCOE and LCOH with a cost-based approach of the derivative value chain in a bottom-up approach

Approach: We focus on a number of carrier pathways that are considered to be most viable for the future use of maritime import infrastructure.

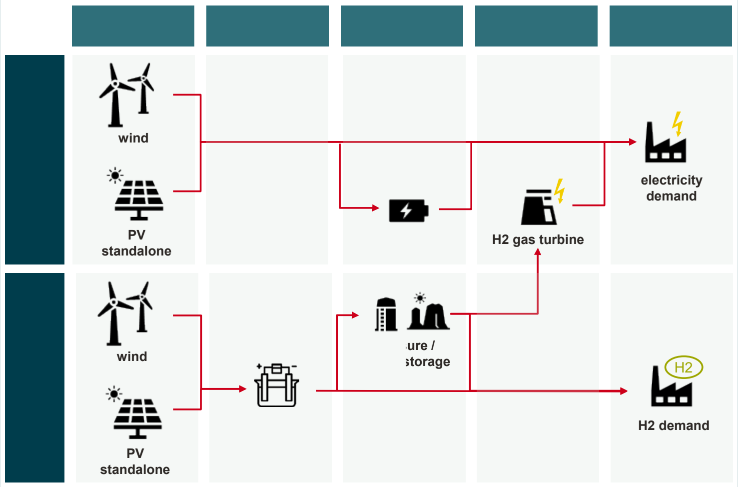
- We rely on **local energy costs** for both near baseload electricity and green hydrogen and **local methane prices** for representative sourcing countries.
- Based on this, we consider the **transformation to different energy carriers** and their **respective transport via ship**; followed by (if applicable) **re-transformation and end-use**. We consider learning curves and specific process characteristics.
- The analysis reflects the **fundamental costs** for imports of renewable and low-carbon energy. It does not reflect market prices (outcomes), tax/subsidy mechanisms such as the IRA or carbon pricing/CBAM.

This section is structured as follows:

- Overview of potential import pathways;
- Description of methodology and main inputs;
- Results: pathway cost bandwidths.

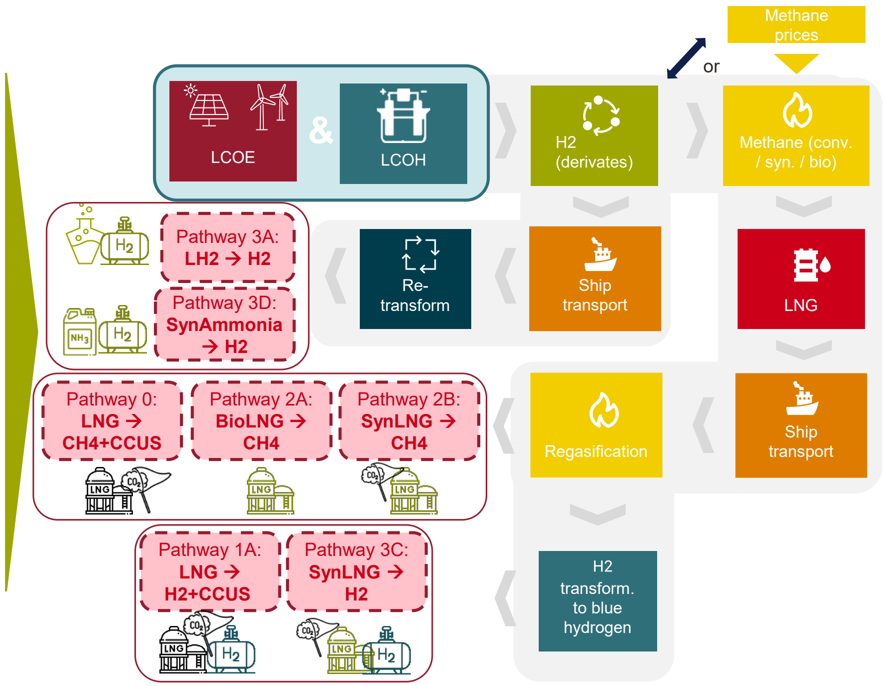
Cost modelling (for SynLNG/H2 paths)

Optimisation model



- Consideration of the years 2025, 2030 and 2045
- Optimisation problem under multiple constraints
- Objective: Minimisation of system costs
- Solved in GAMS (tool for solving large constrained optimisation problems).

Pathway analysis



Source: Frontier Economics

2. Pathway costs 2040 Import pathways for terminals

There are various import pathways for terminal utilisation for the import of renewable/low-carbon gas and fuels – in the next step, we select seven pathways for the detailed analysis

All carrier-specific pathways can be considered for potential hybrid terminal solution (combining the individual pathways).

	0. LNG + CCU/S on site	1. Downstream H_2	2.Upstream greening	3.Upstream H_2	4. e-fuels
	Conv. LNG	A Methane reform.; B Pyrolysis	A Bio LNG; B Syn LNG	A LH2; B LOHC; C Ammonia; D SynLNG	A Ammonia; B Methanol
Upstream production	Natural gas (CH_4)	Natural gas (CH_4)	Bio- & synthetic methane (CH_4)	Production of green H_2	Production of green H_2
Upstream transformation			Enrich / methanise	LOHC / methanise / N2 HB	Ammonia / methanol transformation
Export terminal and shipping	Liquid CH_4	Liquid CH_4	Liquid CH_4	LH_2 / LOHC / Liquid CH_4 / NH_3	Liquid NH_3 / MeOH
Import terminal (EU)	Regasification of CH_4	Regasification of CH_4	Regasification of CH_4	Regasification of liquid H_2 (carrier)	
or Direct liquid consumption	Consumption liquid CH_4	Consumption liquid CH_4	Consumption liquid CH_4	Consumption liquid H_2/ CH4 / NH_3	Consumption of NH3 / MeOH
Further onshore processing		CCS/CCU (e.g. SMR, pyrolysis)			
Transmission, storage and end use	CH_4 + CCS/CCU on site	H_2 (pure or blending)	CH_4	H_2 (pure or blending)	NH_3 / MeOH
Main end-use sector					

Source: Frontier Economics

Legend:
Green hydrogen
Blue/turquoise hydrogen

Source: Frontier Economics

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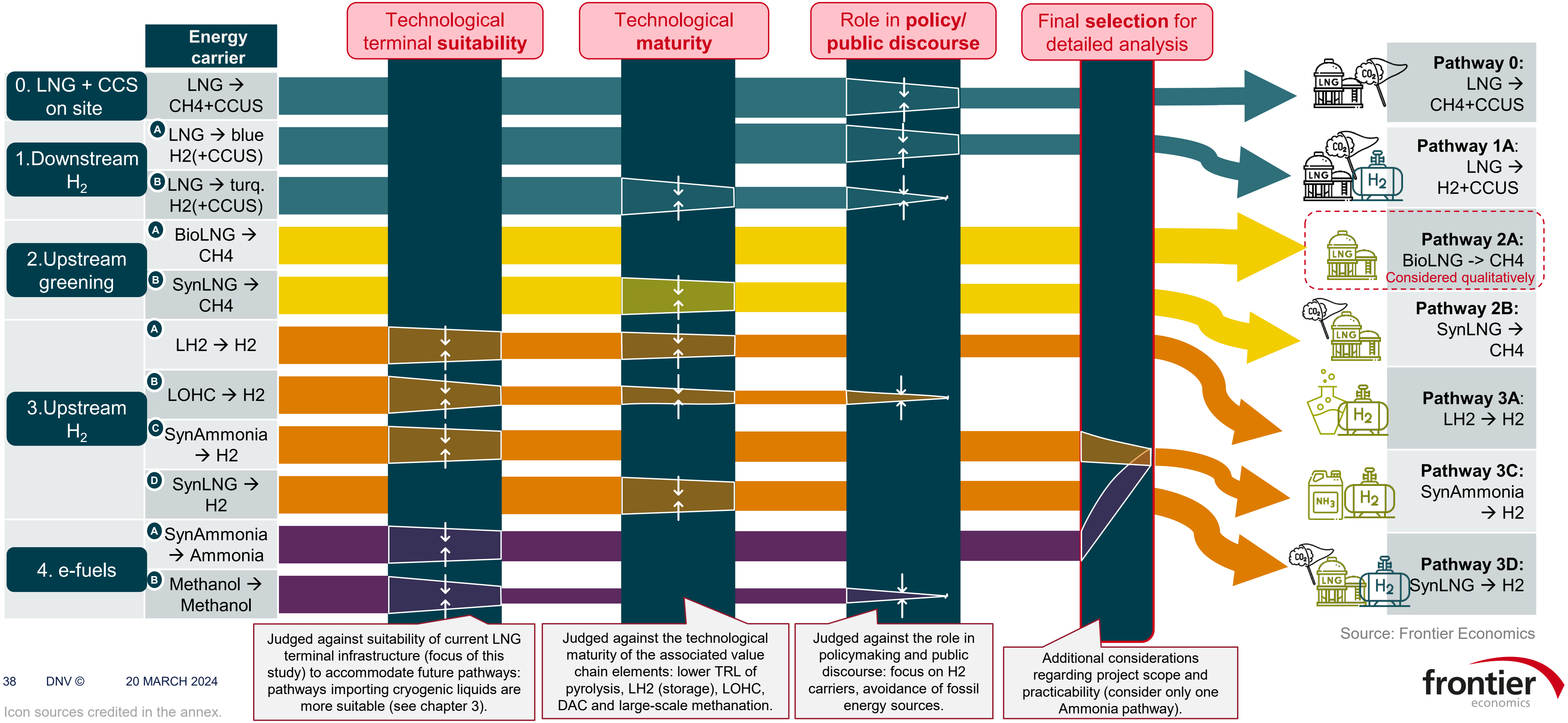
2. Pathway costs 2040 Choosing focus pathways

We have identified seven pathways for renewable/low-carbon gas and fuels that we consider in more detail in the following

! The chart indicates considerations in the pathway selection for streamlining the project analysis: it **does not constitute a (preliminary) evaluation of the pathways!**



Source: Frontier Economics

Icon sources credited in the annex.

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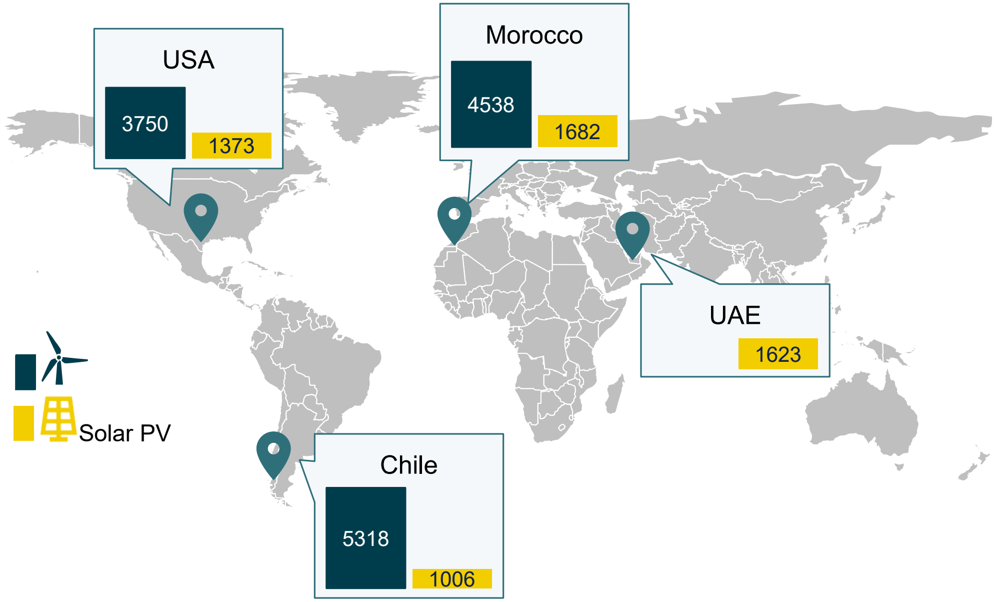
2. Pathway costs 2040 Regional LCOE/LCOH 2040

As a starting point for our cost calculation, we derive regional LCOE and LCOH for near baseload supply for a representative location in each country through our HyLO model

Full load hours of considered locations in sourcing countries



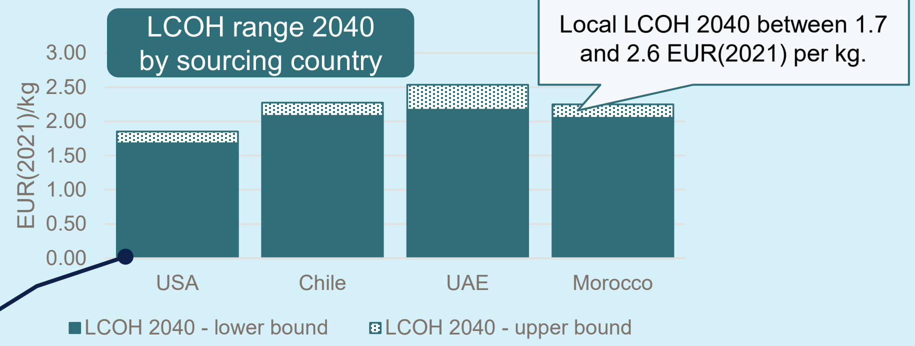
Source: Frontier Economics based on Fraunhofer Global PtX Atlas and Baehr et al. (2023).

As RES sourcing countries we consider **USA**, **UAE**, **Chile** and **Morocco** (via ship) which are representative for other suitable RES-E production countries.

For each sourcing country we consider a **representative RES location** in terms of the annual RES profile and suitability of location.

LCOE/LCOH through cost optimisation of near baseload supply

- Through a linear optimisation model, considering **cost and efficiency assumptions for RES, electrolysis and storage technologies for 2040**, we derive **LCOE and LCOH** for near baseload supply. The model is also considering an hourly baseload demand profile, and country-representative RES generation time series.
- We are **varying capital costs for electrolysis** to cover the uncertainty around learning curves, and to generate a cost range for possible future LCOE/LCOH.
- We **differentiate the WACCs for the LCOE/LCOH calculation** by sourcing country, reflecting country-specific risks/uncertainty for local investments.
  - USA: 5%, Chile 6%, UAE, 6%, Morocco 7%, based on Damodaran (2023).
- **Results for LCOE 2040:** between 39 and 49 EUR(2021) per MWh for the sourcing countries. Central-European LCOE 2040 (for downstream processes) of roughly 66 EUR(2021) per MWh.
- **Results for LCOH 2040:** between 1.7 and 2.6 EUR(2021) per kg for the sourcing countries (see below).



Favourable cost ranges for the USA due to suitable renewable generation profiles for wind and solar, salt cavern availability, and low financing costs (policy mechanisms such as IRA not considered in analysis).

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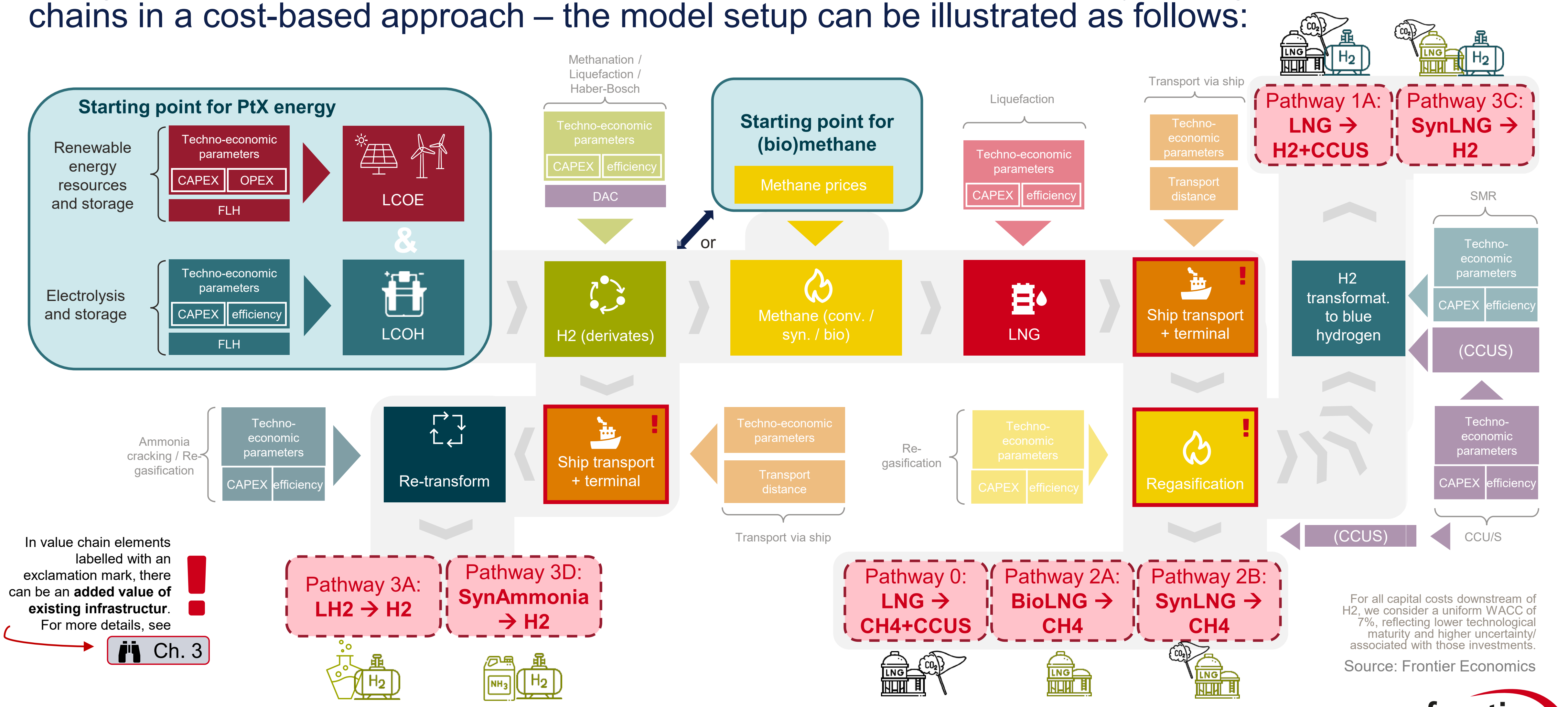
2. Pathway costs 2040 Cost framework

Using LCOH/LCOE results, the cost model considers the import pathways along their full value chains in a cost-based approach – the model setup can be illustrated as follows:



Source: Frontier Economics

Icon sources credited in the annex.

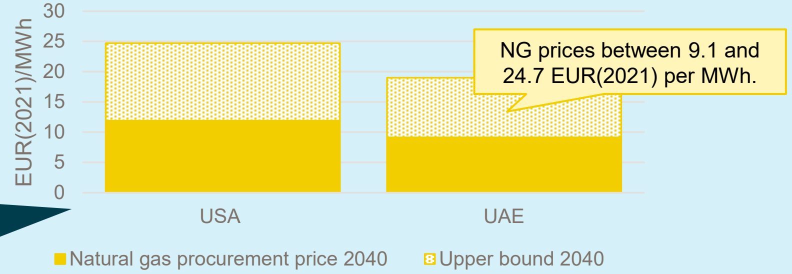
2. **Pathway costs 2040** Reflecting cost uncertainties

To reflect the significant uncertainty about future cost elements, we vary key input parameters to introduce effective cost ranges for all import pathways

Results (bandwidth) and variation

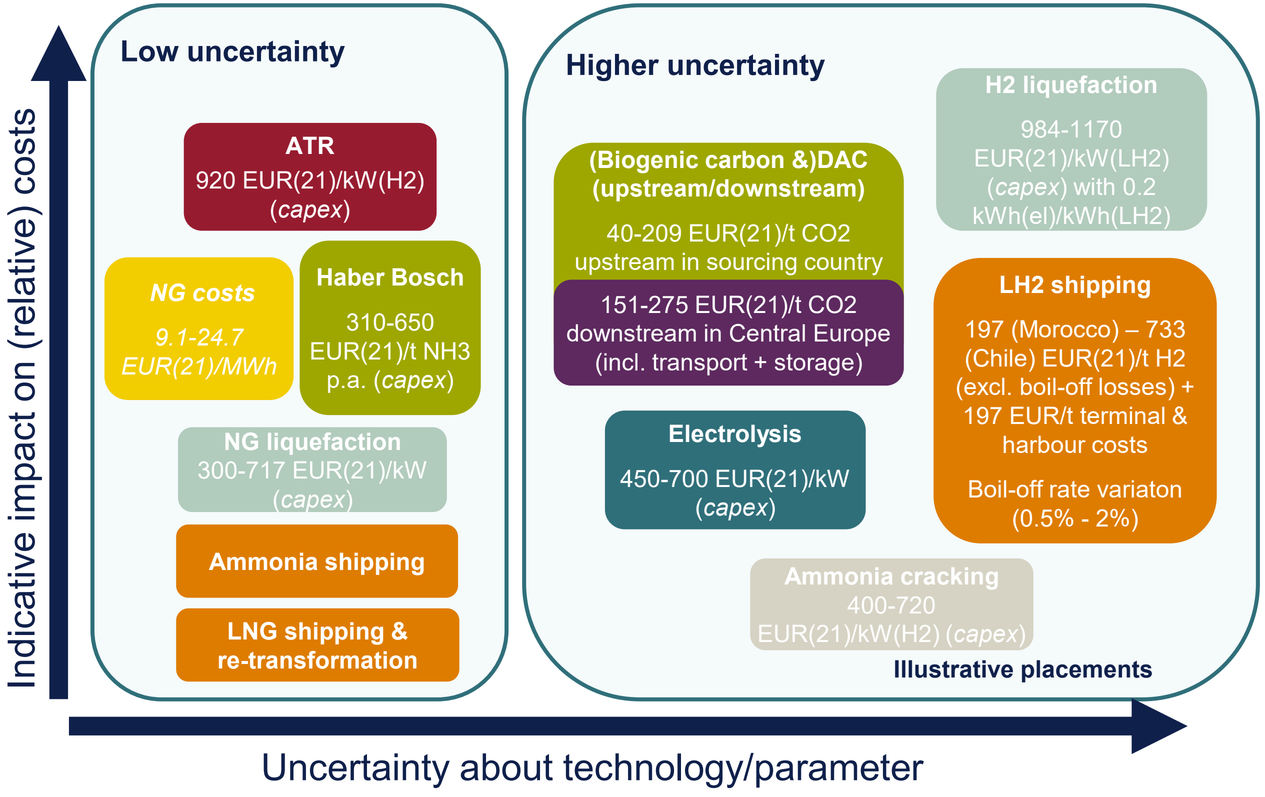
- As different value chain elements for the import pathways are associated with different degrees of uncertainties, e.g. when it comes to their CAPEX or their efficiencies, we **introduce parameter variations** that open up final **cost bandwidth** to reflect a vector of potential outcomes.
- Those parameter variations can have **different root causes of uncertainty**:
  - They affect value chain elements with technological immaturity and therefore uncertain cost and efficiency developments upon market readiness (e.g. LH2 storage, CO2 Direct Air Capture);
  - They affect value chain elements that are mature, but anticipate that further learning curve developments and cost savings are possible (e.g. Ammonia synthesis);
  - Prices for certain input parameters might be exposed to market developments and fluctuations, e.g. the natural gas prices* (see chart below).
  - Moreover, different technologies, approaches and availabilities along the value chain introduce cost ranges for the final supply (e.g. different carbon source for upstream methanation)

Natural gas price range 2040 by sourcing country*



Among the selected sourcing countries, we consider USA and UAE as methane exporters.

Key assumptions and impact on final costs



Source: Frontier Economics

* WEO 2023 STEPS scenario from IEA (2023) as lower price bound for natural gas prices, DNV (2023) plus a lump-sum 25% mark-up considered as upper range.

More information on the assumptions used for the calculation can be found in the annex.

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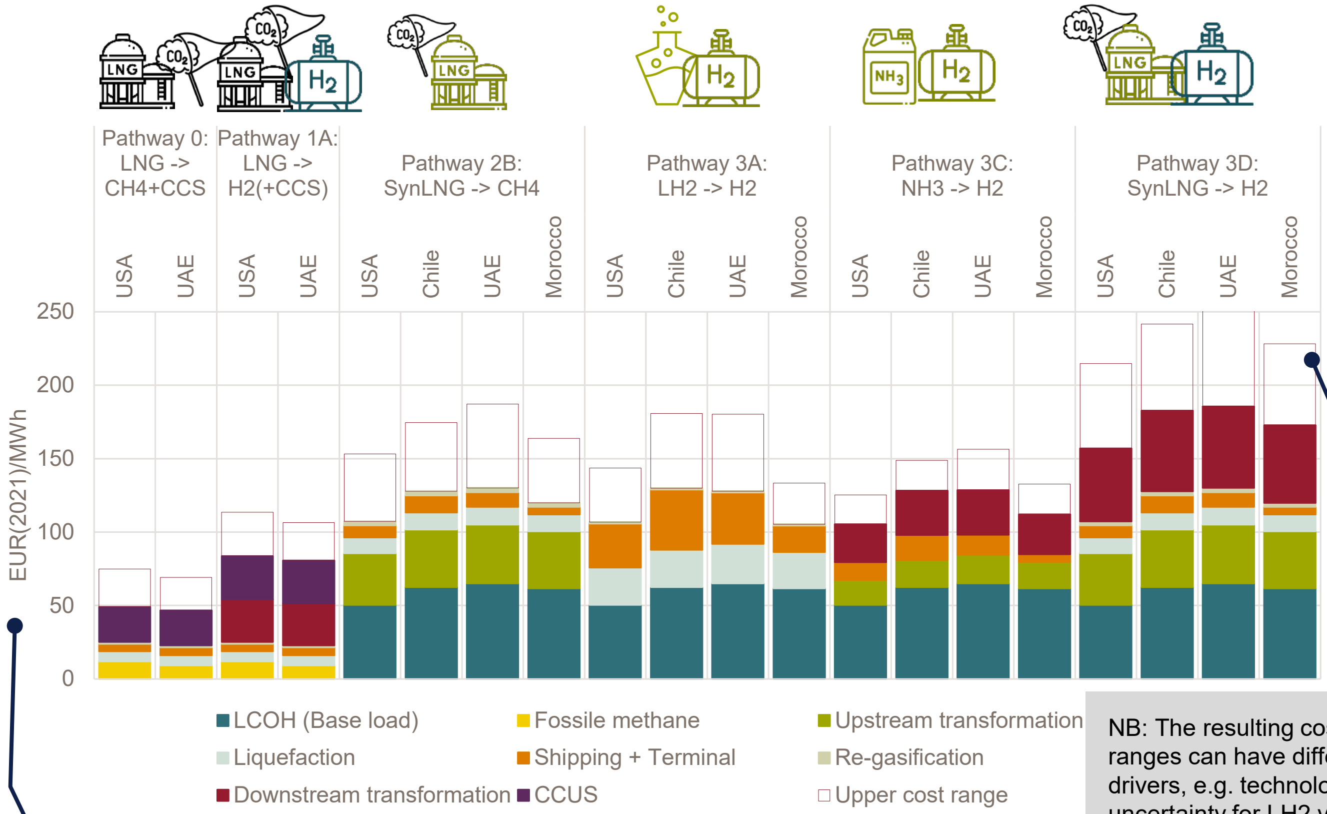
2. Pathway costs 2040 Results across pathways

We find that the sourcing countries offer similar import energy costs across pathways as transport distance plays minor role for most supply costs

- Generally, **most import pathways range in similar final supply cost ranges**, however, with **different dimensions on uncertainty** attached. Also, the cost intensity of different value chain elements differs across import pathways, therefore identifying specific different cost drivers.
- The **pathways relying on conventional LNG and carbon capture at combustion / at ATR** are likely to remain the most cost-efficient options.
- The generation of **synthetic methane**, and subsequently LNG, is a more cost-intensive one – more than 20% of costs are attributed to the methanation process (upstream transformation).
- The **H2 carriers without any carbon involved** along their value chain are **LH2** and **Ammonia**, both ranging in similar cost ranges in the lower cost estimates – however, there is **more uncertainty associated with the LH2 pathway** due to immature LH2 storage.
  For **ammonia**, the most cost-intensive step is the downstream transformation. This also suggests that there is an argument for using synthetic ammonia directly, instead of transforming it back to H2. Uncertainties for NH3 are much lower.
- **Some cost drivers:**
  - Major cost drivers are LCOH and transformation processes (and losses)
    - LCOH: Costs in UAE higher due to less favourable PV profile compared to combined wind/PV profile in USA; also, impact of differentiated WACCs by sourcing countries.
  - Smaller impact of transport costs, however, most pronounced for LH2 (due to boil-off losses + smaller number of round-trips per year for expensive ships)

* Transformation losses are counted towards the associated technology.



NB: The resulting cost ranges can have different drivers, e.g. technological uncertainty for LH2 v. the type of upstream carbon source for SynLNG.

As a **reference point for the willingness-to-pay** for carbon-neutral H2 in end-use: grey H2 with methane from UAE/USA from our 2040-model (methane + ATR costs, i.e. not considering CCUS costs), plus a RED III penalty of 450 EUR(21)/t CO2 would yield **164-197 EUR(21)/MWh**.

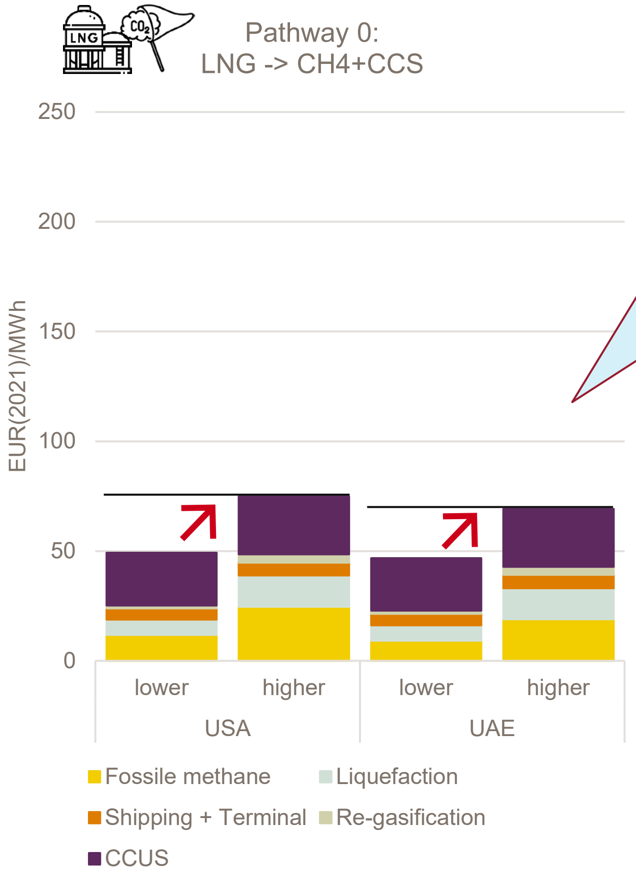
For CH4 in end-use (and therefore, without the ATR), the same calculation would give a **100-125 EUR(21)/MWh willingness-to-pay.**

Source: Frontier Economics

Icon sources credited in the annex.

2. **Pathway costs 2040** Conventional LNG pathways with downstream carbon capture

We consider USA and UAE as sourcing countries for the conventional LNG pathways

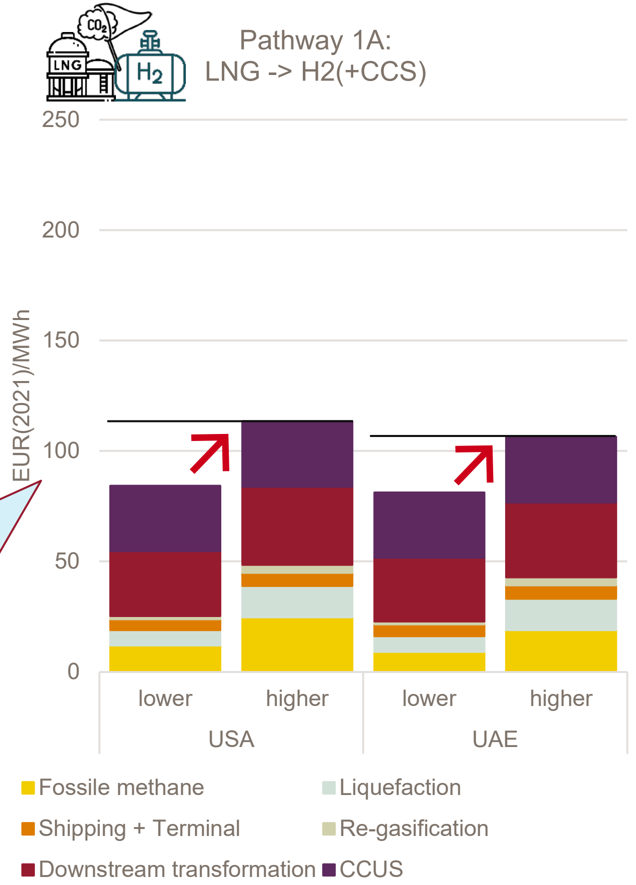


End-use CH4

- This import pathway foresees the end-use of **conventional LNG as CH4** and industrial **carbon point capture** at combustion (downstream), e.g. at a large industrial site.
- Final supply costs range between **47 and 75 EUR(21)/MWh in 2040** in Central Europe.
- A **final supply cost bandwidth** is introduced by varying:
  - The natural gas procurement price;
  - The capital costs of an NG liquefaction unit;
  - The capital costs of an LNG re-gasification unit;
  - A range for costs incurred for leakage emission.

End-use H2

- This import pathway foresees the downstream transformation of **conventional LNG to H2** through ATR and **carbon point capture** at transformation.
- Final supply costs range between **81 and 114 EUR(21)/MWh in 2040** in Central Europe.
- A **final supply cost bandwidth** is introduced by varying:
  - The natural gas procurement price;
  - The capital costs of an NG liquefaction unit;
  - The capital costs of an LNG re-gasification unit;
  - The ATR carbon capture rate;
  - A range for costs incurred for leakage emission.



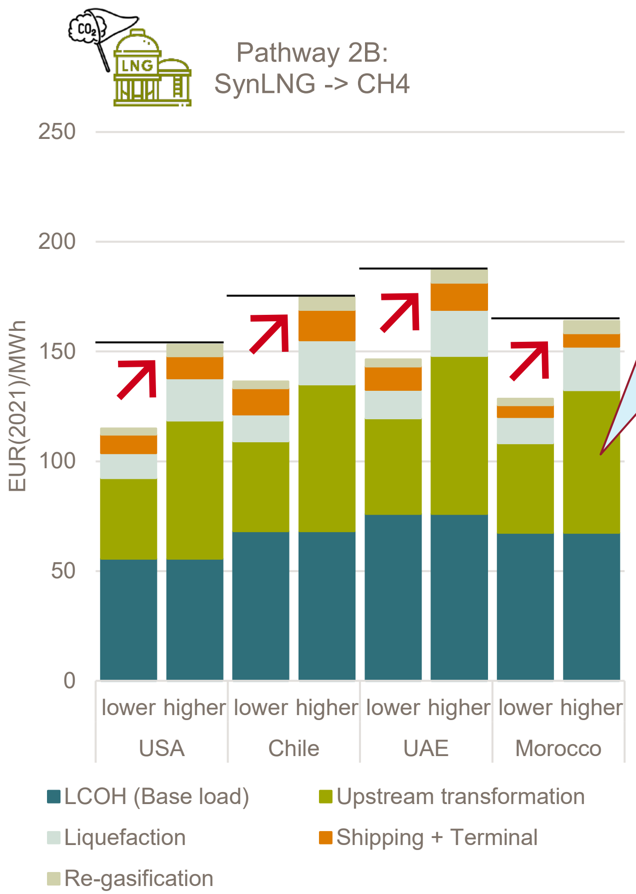
* Transformation losses are counted towards the associated technology.
More information on the assumptions used for the calculation can be found in the annex.

Source: Frontier Economics

Icon sources credited in the annex.

2. Pathway costs 2040 SynLNG-to-CH4 and LH2

These pathways also differ by end-use carrier – Methanation and diff. carbon sources introduce a wide cost range for SynLNG, while LH2 is associated with high future supply costs uncertainties



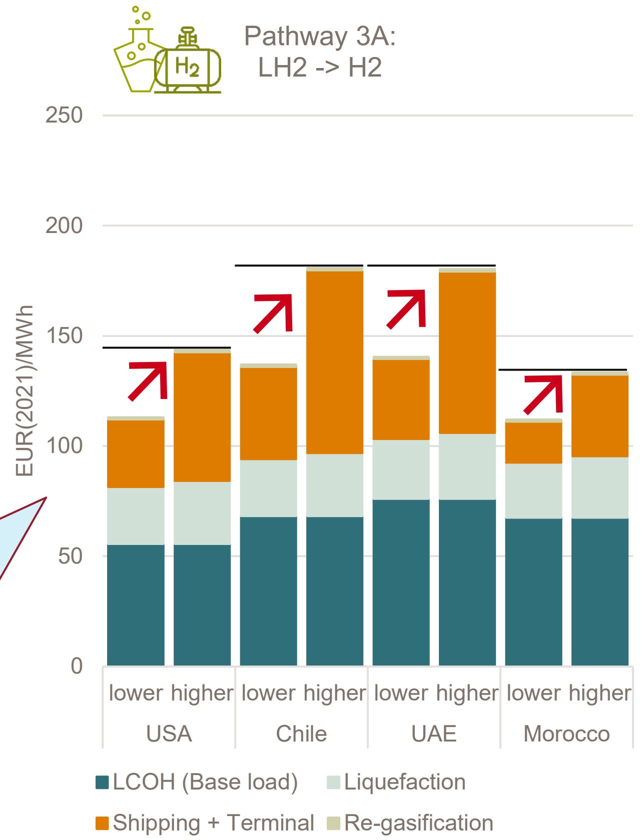
End-use CH4

- This import pathway foresees the upstream transformation of **green hydrogen to synthetic LNG**. No downstream transformation back to H2 is required due to the CH4 end-use – this enables downstream cost savings.
- Final supply costs range between **115 and 187 EUR(21)/MWh in 2040** in Central Europe.
- A **final supply cost bandwidth** is introduced by varying:
  - The capital costs of electrolysis;
  - The carbon source used for methanation (biogenic carbon as cheap source with limited availability, DAC as upper cost bound);
  - The capital costs of an NG liquefaction unit;
  - The capital costs of an LNG re-gasification unit.

End-use H2

- This import pathway foresees the **upstream liquefaction** and downstream re-gasification of **green H2**.
- Final supply costs range between **112 and 180 EUR(21)/MWh in 2040** in Central Europe.
- A **final supply cost bandwidth** is introduced by varying:
  - The capital costs of electrolysis;
  - The capital costs of the H2 liquefaction unit;
  - The boil-off rate during ship transport and being stored in export/import terminal.**

** The LH2 boil-offs during the ship transport are utilised for fuelling the ship, therefore enabling fuel cost savings. For the boil-offs in the terminal, for simplification purposes, no further cost savings are considered.



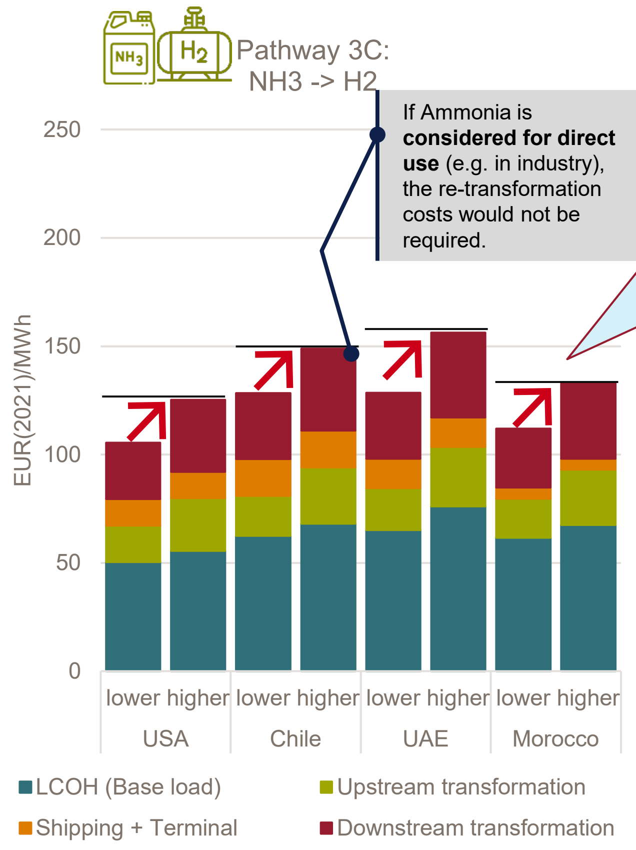
* Transformation losses are counted towards the associated technology.
More information on the assumptions used for the calculation can be found in the annex.

Source: Frontier Economics

Icon sources credited in the annex.

2. Pathway costs 2040 Ammonia and SynLNG to H2

The ammonia pathway is the most prominent one in today's public discourse – significant cost-savings are enabled through the direct end-use of ammonia. SynLNG to H2 will be expensive.



If Ammonia is **considered for direct use** (e.g. in industry), the re-transformation costs would not be required.

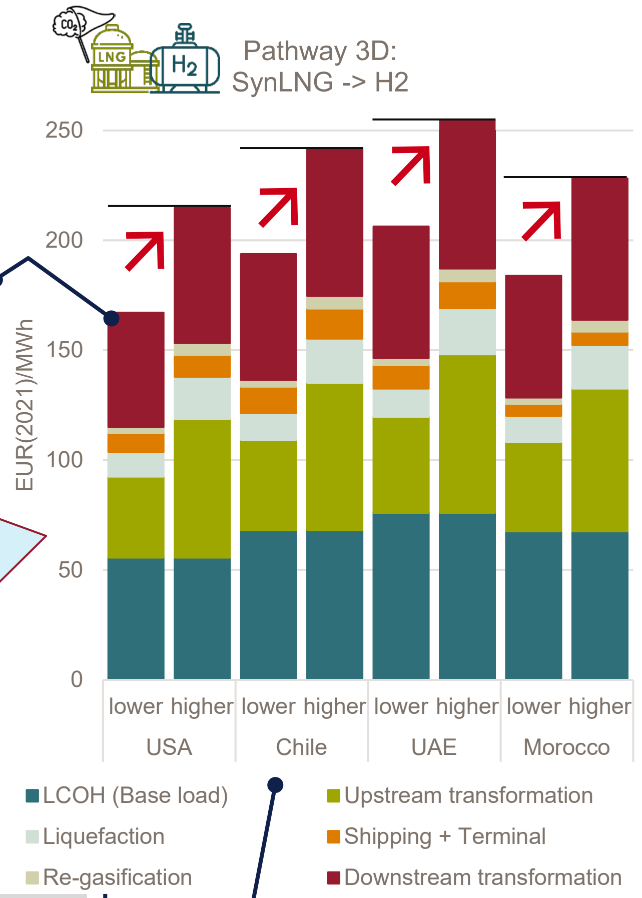
End-use H2

- This import pathway foresees the upstream transformation of **green hydrogen to Ammonia**. The end-use is H2, therefore a downstream tansformation is required.
- Final supply costs range between **113 and 152 EUR(21)/MWh in 2040** in Central Europe.
- A **final supply cost bandwidth** is introduced by varying:
  - The capital costs of electrolysis;
  - The capital costs of Ammonia synthesis;
  - The capital costs of Ammonia cracking.

The downstream transformation is more expensive than for *Pathway 1A: LNG→H2(+CCUS)* because the transformation losses become more expensive with the longer upstream value chain.

End-use H2

- This import pathway foresees the upstream transformation of **green hydrogen to synthetic LNG**. Re-transforming synthetic LNG into H2 comes at high re-transformation costs, rendering this pathway to be the most expensive one considered.
- Final supply costs range between **167 and 257 EUR(21)/MWh in 2040** in Central Europe.
- A **final supply cost bandwidth** is introduced by varying:
  - The capital costs of electrolysis;
  - The carbon source used for methanation (biogenic carbon as cheap source with limited availability, DAC as upper cost bound);
  - The capital costs of an NG liquefaction unit;
  - The capital costs of an LNG re-gasification unit.



A future consideration for this pathway will be the option of a **closed carbon loop** by "recirculation" of the captured carbon back to the production facility via ship. Agora (2023) shows that this could be realised at competitive supply costs (lower costs than DAC-only option).

Source: Frontier Economics

* Transformation losses are counted towards the associated technology.
More information on the assumptions used for the calculation can be found in the annex.

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Icon sources credited in the annex.

Chapter 3. Techno-economic suitability of terminals for the import of renewable and low-carbon gases

3. Terminal benefits Site specific benefits

Existing LNG terminals can provide a strong contribution and accelerate the energy transition

LNG terminals are often situated in a remote area of a harbour with good accessibility by ship, which are well connected to infrastructure, and have space for further development. Permits are already in place for importing LNG. This means large volumes of water can be extracted for heat exchange, strict safety protocols and provisions are in place and the operations (import of energy) are already integrated/considered by the other harbour operations. These aspects are critical for the import of energy in other forms, are unique and often require years of development, negotiation and acceptance.

1. Provide access to energy and facilitate local decarbonization

- Import of energy through terminals provides **access in the absence of or alternative to a fully interconnected back-bone**. The development of the back-bone will take multiple decades before all demand clusters will be fully connected. Large demand clusters are often situated near harbours where a terminal might be present. This allows for supply and storage of energy through the terminal. Use of existing terminals or expansion could even **accelerate development of a local transport/distribution** network which can later be connected to the back-bone.

2. Utilize potential of terminals to provide storage and balance to the energy system

- Balancing the energy system will become more challenging in a hydrogen network (with lower control over production of H2 compared to natural gas) and terminals can still provide a solution. Storages such as salt caverns can also provide such services but are not available in each region.
- Although energy storage capacity will be reduced with other carriers compared to LNG, the energy storage capacity of an existing terminal is significant and can provide an important contribution to Europe's hydrogen storage requirements. An average storage tank in a terminal can **store significant volumes of energy,** comparable or more than a hydrogen salt cavern.

3. Synergies can be identified where especially cryogenic energy from the (Syn)LNG regasification process can be utilized for a range of purposes

- It can reduce energy requirements/costs for **re-liquefying** the carriers in other storage tanks, especially NH3.
- It can be used to **pre-cool** hydrogen before it is compressed. Especially for high pressures found in mobility.
- **Cryogenic power generation** is currently being developed with a specific focus on the combination with LNG terminals.
- Capture and liquefaction of CO2. **Cryogenic CO2 capture (CCC)** is currently being developed and then combined with an energy terminal, could provide a cheap option for (high purity) carbon capture. Additionally, the cryogenic energy is suitable for **liquefaction of CO2.**

3. Terminal benefits Terminal specific benefits

Existing LNG terminals can provide a strong contribution and accelerate the energy transition

1. Existing terminals can contribute and accelerate the import of energy through various pathways

including: LNG | LH2 | Ammonia | Methanol | LOHC | Bio-Syngas | a combination of all (hybrid)

- Existing terminals can facilitate the import through the mentioned pathways and potentially **reduce capex up to 63%** compared to newly built import terminals depending on the pathway. This does however require adaptations that need further research to fully evaluate suitability.
- Suitability of the storage tank material is the main concern as information is still scarce and is has the biggest cost impact (~50%). **Further research into material suitability** is required, especially regarding liquid H2 and NH3.
- Due to a difference in physical properties, many other components will require replacement such as pumps, compressors, control and metering systems, safety systems and possibly piping. However, **not all components might be needed anymore** if the imported carrier will be used or transported directly without regasification. This is likely the case with NH3, for methanol and LOHC where regasification will not apply at all.
- Further evaluation on a situation basis is required for safety and environmental aspects. These are highly location specific. Especially for LH2 and NH3, **the safety and environmental risk profile will increase.**
- Terminals can be **transformed gradually** allowing for a multi carrier or **hybrid solution** that allows for a more flexible and versatile energy transition. The high accessibility of terminals with deep docks and strategic locations (access to demand and infrastructure) are advantageous. Although import of each carrier will require a dedicated system, the location can still allow for hybrid import.

3. **Terminal benefits** Contribution in Energy Transition

Existing LNG terminals can facilitate the energy transition and provide significant benefits. We identify and substantiate these benefits.

Approach: We identify the benefits of existing terminals and their contribution to the future energy system. In our approach we distinguish between 2 categories:

1. Site specific advantages
We substantiate the identified benefits and reflect on the potential role in a future energy system. Some benefits are summarized below:

- The site of an LNG terminal is specifically intended for the import of energy. Required infrastructure such as a dock, jetty and access to pipelines or local demand is present and non-discriminatory access to third parties is available.
- Additionally, the presence of the storage capacity of a terminal can provide significant benefits to the area to secure a balanced supply of energy and provide peak-shaving to energy networks.
- Finally, many terminals are located in harbours with various industry processes in the vicinity. The availability of cold (cryogenic energy) and heat allows for multiple synergies.
- Potential to benefit from existing authorisation and local acceptance with already existing upper-tier Seveso European guideline compliance.

2. Terminal specific advantages

- Existing LNG terminals can be adapted to facilitate other commodities. Significant cost savings are possible when utilising suitable components from existing terminals. Commodities or carriers include:
  - LNG
  - LH2
  - Ammonia
  - Methanol
  - LOHC
  - Bio-Syngas
  - Hybrid or multi-carrier solutions

We assess the suitability of existing terminals to facilitate other pathways and focus on the main components. We also estimate the potential cost saving for re-using the suitable components.

Structure
The structure of this section follows the bullets provided above and will first focus on the site-specific benefits and later focus on the terminal specific benefits.

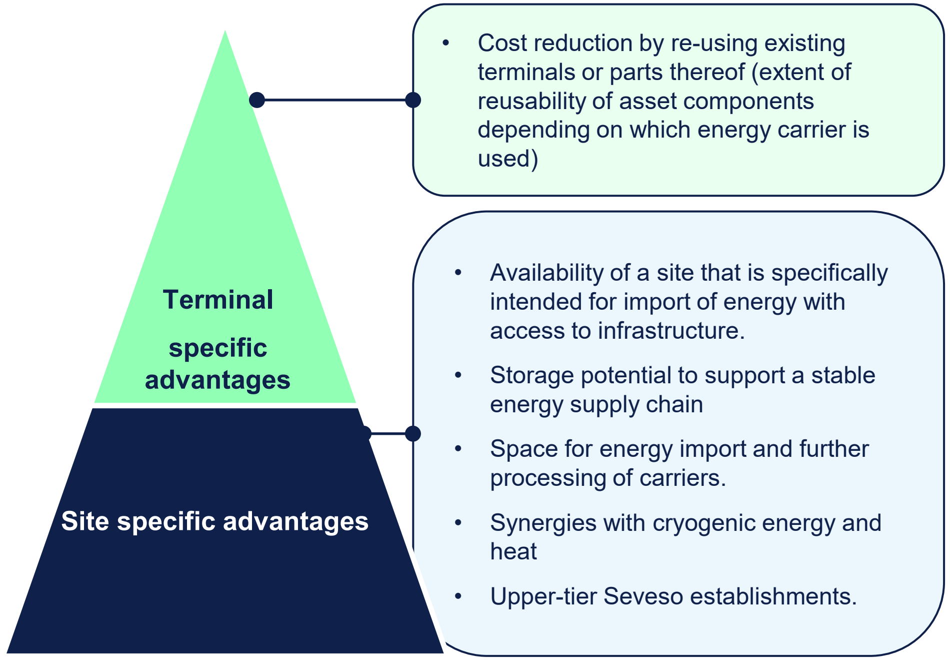


Figure: Site and terminal specific benefits of existing terminals
Source: DNV

3. **Terminal benefits** Site specific benefits

Background

LNG terminals are often situated in a remote area of a harbour with good accessibility by ship, which are well connected to infrastructure, and have space for further development according to some operators. Permits are already in place for importing LNG. This means large volumes of water can be extracted for heat exchange, strict safety protocols and provisions are in place and the operations (import of energy) are already integrated/considered by the other harbour operations. These aspects are critical for the import of energy in other forms, are unique and often require years of development, negotiation and acceptance. The availability of such as location, compared to having to develop a greenfield terminal has significant benefits.

- The docks at the terminal are made/dredged for LNG tankers with a deep draft and is likely also accessible for other types of ships (e.g. LH2, NH3, Methanol, etc.).
- A jetty is already in place which is expensive in green-field.
- Access to energy, infrastructure and local decarbonization
  - Alternative supply infrastructure which can accelerate decarbonization
  - Decarbonization of local demand and connection to NG infrastructure.
  - Extended use of the location/site for further commodity processing.
- Storage potential and peak shaving
- Synergies related to cryogenic energy from the gasification process can be utilized for other purposes.

These benefits are further elaborated on the following slides.

Source: DNV

3. **Terminal benefits** Site specific benefits

Access to energy and local decarbonization

Access to energy and accelerate decarbonization

The presence of a terminal allows (non-discriminatory) access to energy. It could be an alternative or addition to other hydrogen/energy infrastructure such as the hydrogen backbone. Development of such infrastructure can take multiple decades while a terminal can be available in relatively short time. For hydrogen to be transported from e.g. North Africa to all EU demand clusters is will require a fully developed and interconnected backbone.

While the backbone is still being developed, it will take decades before all demand clusters are interconnected and a stable system (with storage) is in place. Large demand clusters are often situated near harbours where a terminal could be present. The terminal can provide access to hydrogen import while the backbone is still in development. This can therefore accelerate the decarbonization of local demand and possibly accelerate the development of a local hydrogen transport/distribution network which can later be connected to the back-bone

When building on the site specific benefits and complementing the LNG import capabilities to hydrogen and derivatives, it is likely that the total capacity will be extended or part of the capacity will be converted from LNG to hydrogen (derivatives). This allows for a more gradual switch and higher flexibility for importing different carriers while the EU energy markets are still developing/rearranging.

Decarbonization of local demand

By facilitating the arrival and distribution of green energy carriers, terminals can contribute to reducing carbon emissions associated with local energy and feedstock demand as imported green hydrogen (derivatives), biofuels and or e-/biomethane can serve as cleaner alternatives to traditional fossil fuels:

- Shipping: Transitioning from conventional marine fuels to green energy carriers, such as green ammonia or methanol, for ship propulsion can significantly decarbonize local shipping activities.

- Harbours: Implementing shore power infrastructure at ports based on imported green energy carriers allows ships to connect to the local electrical grid while docked, enabling them to turn off their engines. This reduces the reliance on onboard fossil fuel generators, minimizing emissions in and around the harbour.

- Industry: Introducing green energy carriers in local industrial processes can lead to the decarbonization of e.g., manufacturing of fertilizers using green ammonia and/or refineries using green hydrogen.

- Power Plants: Repurposing traditional fossil power plants in the vicinity of harbours where possible for cleaner alternatives like green hydrogen (derivatives) contributes to the decarbonization of local power generation.

Extended use of the location/site for further commodity processing

Some terminals have or can free up space for further processing of an imported carrier. The site provides good facilities and conditions for such activities (a site with established safety processes, acceptance for handling liquids and gasses and access to infrastructure for further transport or local demand). Safety and environmental risks should however be evaluated in the case of other carriers as risk profiles will change.

An example could be the import of ammonia which can be transported/utilized directly or alternatively be cracked to hydrogen for injection in the backbone. This allows for flexibility to supply different markets (ammonia and hydrogen from the same terminal. Technological developments to flexibly run ammonia cracking processes further support this advantage.

3. Terminal benefits Site specific benefits

Storage potential and peak shaving

The storage potential of energy terminals can provide a significant contribution to balancing fluctuations in the energy system and increase the robustness.

Storage

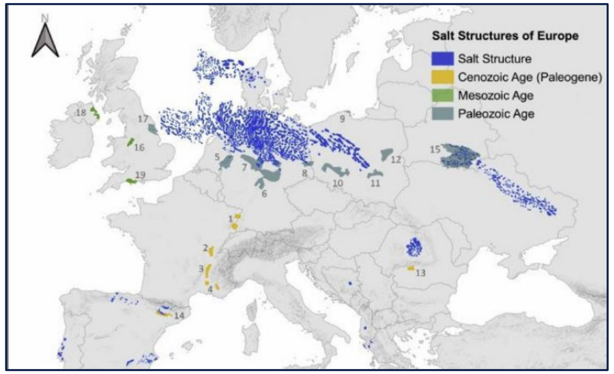
Terminals can provide a significant contribution to the storage capacity. Energy production from renewable energy will provide large fluctuations and require significant storage volumes to cover seasonal differences in Europe. The import of energy carriers itself will already reduce the need for storage, but the storage capacity of the terminal itself can further reduce the storage need.

Balancing services

LNG terminals are currently providing peak-shaving services to the natural gas grid. With large demand fluctuations the pressure in the natural gas grid will drop which reduces capacity and provides operational challenges. LNG terminals can increase their send-out capacity in a short time-frame to balance demand and supply and assist the gas grid operator.

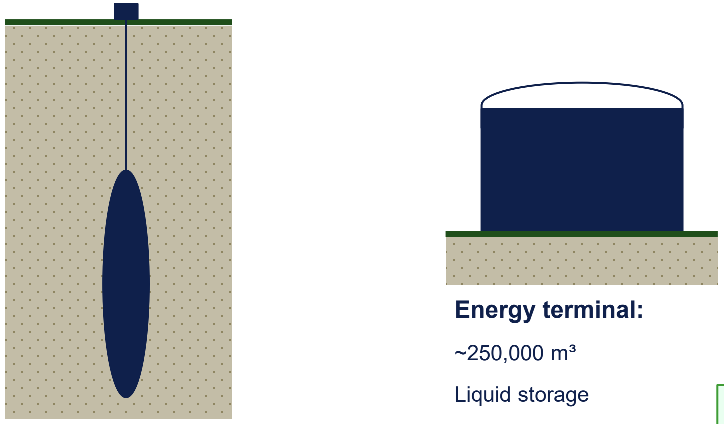
In a future energy system such services can still be required. Pressure fluctuations in a 100% or blended hydrogen network can have a worse (compared to NG) effect on the pipeline integrity due to hydrogen embrittlement. Solutions to balance pressure in the grid will therefore be needed.

Alternatives to the peak-shaving capabilities of an energy terminal are underground hydrogen storage (salt caverns) or flexible hydrogen production/consumption. To evaluate the contribution of energy terminals the potential future energy system should be simulated. The map on the right shows the dispersion of salt structures across Europe (in blue). Salt caverns are mostly situated in North Germany and to support a cross-EU backbone, terminals can therefore provide an alternative in other areas.



Source: TNO, Bulk Storage of Hydrogen EU perspective, 2022

Comparison between storage potential of terminals and salt caverns
The storage potential of an average LNG terminal of 250,000 m³ can be up to 3.5 times higher compared to a single salt cavern (depending on which carrier, the volume of the storage tank and the volume and pressure of the cavern). It should however be noted that the holding period for LNG, LH2 and ammonia, has limitations due to boil-off and is therefore less suitable or energy intensive for long periods of time, e.g. seasonal storage, but it will still provide a significant contribution to the EU storage capacity. The combined storage potential of all terminals in the EU and UK is good for 18.1 – 51.4 TWh depending on the carrier.



Salt cavern:

100,000-1,000,000 m³

Gaseous H2 storage, 150-200 bar

~100 – 250 GWh

Energy terminal:

~250,000 m³

Liquid storage

LNG: ~1,670 GWh

LH2: ~700 GWh

NH3: ~890 GWh

Methanol: ~ 780 GWh

LOHC: ~330 GWh

Note: these storage sizes are theoretical and not yet available or proven for all carriers (e.g. LH2 and NH3)

Figure: Comparison between storage potential of terminals and salt caverns
Source: DNV and TNO, Bulk Storage of Hydrogen EU perspective, 2022

3. Terminal benefits Site specific benefits

Synergies

To further enhance the potential of LNG or energy terminals in the future, potential synergies can be utilized. These synergies mainly resolve around the availability of cryogenic energy which can be used for various purposes.

Cryogenic energy is available when re-gasifying LNG or LH2. In current practice sea water is often used to warm LNG so it changes phase from liquid to gas. In this case the cryogenic energy is not utilized while it could still be useful to provide cold to processes that would otherwise consume energy to generate the cold. Multiple of such uses can be identified.

- In the case of a hybrid terminal, cryogenic energy from LNG or LH2 regasification can be used to reliquefy ammonia boil off. The storage temperature of ammonia is much higher which makes the cryogenic energy from LNG or LH2 suitable to reliquefy ammonia boil-off from an adjacent liquid storage tank. Additionally, the ammonia in the storage tank can be cooled to lower temperatures to prevent/minimize boil-off and to extend the holding periods. This can be especially relevant to support a flexible energy system based on renewable energy and increase the energy storage capabilities as discussed earlier.

- Cryogenic energy can be used as a first step to cool down gaseous hydrogen before (re-)liquefaction of boil-off gas. It should however be considered if re-liquefaction of boil-off is needed or if direct injection or use is more feasible.

- (Pre-)cooling of gaseous hydrogen can also be advantageous when hydrogen is to be compressed to overcome overheating with hydrogen. When hydrogen is being compressed it will heat up and will require cooling. Additionally, hydrogen will also heat up when decompressed due to the Joule-Tomson effect. This will increase the time required for hydrogen filling or fuelling. When the terminal is at a location where local hydrogen demand, especially in mobility or shipping is foreseen this can be an advantage.

- Cryogenic power generation is a potential method to recover the power consumed with the liquefaction process. Power can be generated through expansion in a Rankine cycle to convert thermal energy in mechanical energy and generate power. Many terminal operators already utilize this at small scale to optimize terminal operations.

- Cryogenic CO_2 capture is still in an early development but could potentially find synergies with LNG or LH2 terminals. For some cryogenic carbon capture (CCC) technologies, the cryogenic energy from LNG is a suitable source but require further development. High purity CO_2 is captured and can be stored or used as feedstock for other processes.

- Liquefaction of CO_2 for transport - The cold released from LNG regasification presents an opportunity for efficient CO_2 cooling to meet transport requirements. The specific pressure and temperature at which CO_2 is delivered to terminals determine whether additional compression and cooling are necessary to align with the shipping vessel requirements. According to ZEP[A], smaller vessels, exemplified by current food-grade CO_2 transport vessels with a capacity of approximately 10,000 m³, typically operate at a medium pressure of around 15 barg and a temperature of -30 degrees Celsius. In contrast, larger vessels exceeding 10,000 m³ are more inclined to function at a low-medium pressure of approximately 7 barg and a temperature of -50 degrees Celsius. In cases where CO2 delivered to the terminals does not meet those requirements, the residual cold from LNG regasification could be effectively used for the cooling of the CO_2, leading to a reduction in overall energy demand and associated costs.

  Terminal operators such as Elengy are already further developing the use of cryogenic energy to liquify CO_2 and aim to implement this in their terminal(s).

A: ZEP (2022). Network Technology Guidance for CO2 transport by ship. ZEP/CCSA. https://zeroemissionsplatform.eu/wp-content/uploads/ZEP-CCSA-Report-on-CO2-transport-by-ship-March-2022.pdf

3. **Terminal benefits** Terminal specific benefits

LNG Import Terminals - Status Quo

Working principle

LNG is loaded from the LNG tanker through the jetty and loading arms to a large storage vessel. The storage vessel is insulated to minimize the regasification of LNG (boil-off) and is kept close to atmospheric pressure. Any boil-off is taken to the boil-off gas system (BOG) where the gas is reliquefied by means of compression and cooling. Before injecting natural gas into the transport system it has to be regasified. The LNG is extracted from the storage tank by means of low-pressure and high-pressure (LP and HP pumps) to the regasification unit. Here, the LNG passes heat exchangers to regasify before it is injected into the grid. The figure on the right provides a process overview of an LNG terminal. Additionally, a CAPEX breakdown is provided for the main components. The main components can be identified as follows:

- The jetty and loading arms (note that the jetty is a considerable cost component, but costs are highly situation & site-dependent). Site specific civil engineering is not included here, which could be a considerable cost component.
- The storage tank
- The LP and HP pumps
- The boil-off gas system (BOG)
- The regasification unit
- Piping
- Safety and control systems

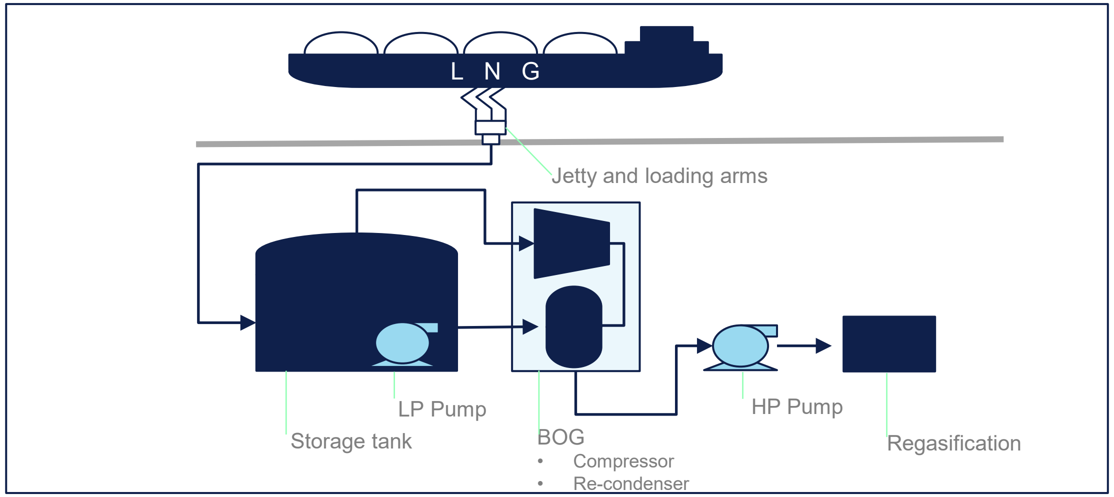


Figure: Main components and process steps of an LNG terminal
Source: DNV

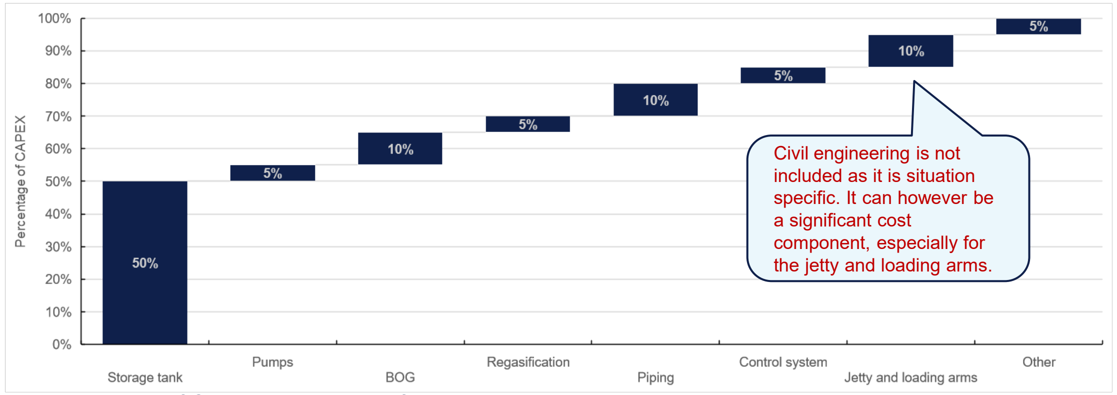


Figure: Estimate of CAPEX break-down of terminal equipment
Source: Er, Conversion of LNG Terminals for Liquid Hydrogen or Ammonia, 2022"
and "Black&Veatch, Hybrid LNG & Ammonia Infrastructure: Key to a Green Economy, E-book"

3. Terminal benefits Terminal specific benefits

Criteria for repurposing

The main function of current LNG terminals is the import of energy. In a future landscape this function can also be fulfilled for other energy carriers. Repurposing existing terminals can be advantageous due to potential lower costs, the location which is already used for energy import and the potential connection to infrastructure. The feasibility for repurposing existing terminals will be situation dependent and not all terminals will be suitable. The most important factors are described below but the main focus for this section will be on the design, safety and permitting aspects.

- **Design -** The design requirements of a terminal can significantly change when converting to another energy carrier. The foreseen alternative energy carriers have a wide variety of physical properties (table bottom right) which can have a big impact on component suitability. Especially the triple point temperature and density of a substance has a big impact.

  Furthermore, there can be interactions between certain materials and the carriers. Corrosion and cracking are some of the key concerns.

  Finally, for some components or materials it is still unknown if these are suitable and require further research and testing.

- **Safety and permitting –** Some carriers like LH2 and NH3 will likely have in increased safety and environmental risk profile. LH2 can pose additional safety risk due to its lower flammability and explosion limits compared to LNG. NH3 is extremely toxic and can pose both a significant safety and environmental risk. This will have an impact on the required safety systems, certification (e.g. ATEX) but also on the permitting.

  Furthermore, regulation might not yet be present or suitable for the increased volumes of a certain carrier.

Below we list additional aspects that are relevant for repurposing but these will be situation dependent and will not be evaluated further in this study.

- **Asset lifetime –** The asset lifetime will play a role in the overall attractiveness for repurposing. For a system that has already largely been depreciated and approaching the end of its technical or economic lifetime it is likely more attractive to build a new terminal.

- **Duration of existing contracts –** Some terminals will be bound by contracts for importing LNG specifically. It should be evaluated case by case how flexible these contracts are and what the effects will be of termination before alternative carriers can be imported.

- **Competition –** When a terminal will facilitate the import of an alternative carrier, the competitive position can change. For the import pathway of methanol or LOHC, petrochemical terminals might be better suited and have a competitive edge over LNG terminals.

- **Post transport or processing –** The availability of infrastructure to further transport the imported carrier or space for further processing (cracking or dehydrogenation) should also be considered. It should be considered if the imported carrier can be used locally and directly, or if further transport or processing is needed. Transport can be done by dedicated infrastructure such as pipe, rail or road, or H2 blending into the natural gas grid could be considered. With carriers like LOHC, dehydrogenation as a for of post processing is required which will require space. Additionally, any residual substances (dehydrogenated LOCH) might have to be shipped back to the location of origin which required a loading infrastructure.

	Unit	LNG or e-/bio-methane	Liquid hydrogen	Ammonia	Methanol	LOHC
Formula		CH_4	H_2	NH_3	CH_3OH	DBT
Boiling point	°C	-162	-253	-33	65	390
Liquid density	Kg/m³	440-500 @ boiling point	71 @ boiling point	653-674 @ boiling point	792 @ 20°C	870 @ 20°C
Heating value	MJ/kg LHV-HHV	50-54 @ boiling point	120-142 @ boiling point	19-23 @ boiling point	19.9-22.7	7.9-9.3
Volumetric energy density	GJ/m³ LHV-HHV	23-24	8.5-10	11.5-17	15.8-18	6.8-8
Flammability range	% volume in air	5-15	4-75	15-28	6.7-37	-
Ignition energy	mJ	0.28	0.02	380-680	0.15	-

Figure: properties of different hydrogen carriers
Source: DNV

3. Terminal benefits Terminal specific benefits

Liquid Hydrogen

Energy import through liquid hydrogen is currently not a proven pathway. Technology and proven/accepted standards are not yet in place but experience from other industries on designing and handling liquid hydrogen could provide some guidance. The novelty of designing terminals for liquid hydrogen will therefore add challenges but might also lead to conservatism with regard to design and use of materials. According to Fraunhofer[A], Partial re-use of exiting LNG terminals is feasible for liquid H2, but with significant limitations and challenges. It is likely that most terminals cannot be repurposed for LH2.

Design

The biggest challenge is component and material suitability. The low storage temperature provides challenges with regard to insulation levels and an increased boil-off rate. Reliquefication of the boil-off is challenging and uneconomic but it could be directly injected into a hydrogen grid if available. Another challenge is the used material in storage tanks. This is usually 9% nickel steel which is considered unsuitable for liquid hydrogen. Some terminals use high alloy stainless steel (304L or 316L) which is considered to be compatible, but only a limited number of terminals use these steels. Furthermore, the storage capacity of a terminal will be reduced by a factor of 2-3 due to the lower volumetric energy density.

Re-use of the storage tank, the largest cost component, is therefore highly dependent on the applied steel and the acceptance of lower storage capacity and higher boil-off. Increasing the insulation level and replacing the steel will be challenging and likely uneconomic compared to building a new storage tank.

Other components of the terminal are not suitable and need replacement.

- All pumps will need replacement due to the different density of liquid hydrogen and it is likely that the pumps are also not suitable with regard to the low temperatures and safety requirements.
- Compressors in the boil off system are not suitable for the application with gaseous hydrogen and reliquefication requires a specialized system. The replacement of the BOG could be omitted to save costs and energy losses by directly using the boil-off gas for local uses or by injecting it to a hydrogen pipeline.
- All piping needs to be replaced due to material suitability and insulation. Vacuum insulated piping is needed to prevent the surrounding air to solidify around the piping.
- Metering and safety systems will not be suitable to properly measure or detect liquid or gaseous hydrogen. Flow metering and liquid level metering is not suitable for the measurement of liquid hydrogen. Furthermore, in case of any leaks, detection systems will not pick up leaks of hydrogen and will therefore need replacement.
- The suitability of the vaporizer is to be studied further.

Safety and permitting

The safety and environmental risks will need to be evaluated on a situation basis. It is expected that the safety risk profile of LH2 will increase due to higher flammability and explosion risk. This can have an impact on the safety contours and overall permitting. Additionally, due to novelty of LH2, regulations, permitting, environmental and safety will likely require further evaluation and development in general.

A: Fraunhofer, Conversion of LNG Terminals for Liquid Hydrogen or Ammonia, 2022

3. Terminal benefits Terminal specific benefits

Ammonia

Ammonia is already traded globally at bulk. Existing design practices and experience in building and operating such terminals can therefore be used to further expand the import pathway of H2 through ammonia. Furthermore, new LNG import terminals in Germany have to be "ammonia ready" if they plan to operate after dec 31 2043[A]. studies on the conversion of LNG to ammonia terminals or building "ammonia ready" terminals have already been conducted by Fraunhofer[B] and by Black&Veatch[C]. The general conclusion is that existing terminals can be repurposed but there are some limitations and some components still require replacement.

Design

Again, the biggest limitation resolves around the storage tank. The suitability of the commonly applied 9% nickel steel in LNG storage tanks for ammonia still requires further research. There are concerns about corrosion when 9% nickel steel is exposed to ammonia and research into this topic is limited. Further evaluation is therefore key as it has a significant impact on the degree of repurposing existing LNG storage tanks to ammonia. If the material is not suitable there are examples where operators intent to replate the interior of the storage tank or to provide a membrane which is currently being considered for the storage tanks on LNG ships. In addition, the energy storage capacity of the terminal will likely be reduced (50%) due to lower energy content and high liquid density of ammonia compared to LNG. Ammonia is heavier and therefore, the tank structure (walls and foundation) might not be strong enough.

The insulation level however is sufficient. Ammonia is stored at higher temperatures and requires less insulation compared to LNG. According to Black&Veatch[B] It is expected that boil off will be reduced to 60% with ammonia compared to LNG.

There are some components such as the BOG system and vaporizer that might also be suitable for repurposing:

- The lower boil-off also has consequences for the BOG system. The lower boil-off volumes can lead to an inefficient operation of the compressors. Furthermore, material suitability of compressors and sealings should be evaluated case by case.
- The vaporizer should also be evaluated further on material suitability and if the heat exchange will be sufficient. It should however be evaluated if vaporization is needed. Uptake of ammonia in local markets might be preferred in liquid form as a fuel or as a feedstock.

Most other components will unfortunately need replacement:

- LNG pumps are not suitable for ammonia due to the higher density and design specification with regard to temperature and sealing.
- Piping and supports will also require replacement due to higher density, possible corrosion and issues with gaskets.
- The metering and control systems should be further evaluated for use with ammonia. The valves and metering devices will have to be adapted to the different physical properties. In some cases, recalibration and a change of control setpoints might be sufficient, but replacement is not ruled out.
- It is likely that at least the safety metering will not be able to detect ammonia leakages. Furthermore, an increased safety risk profile (toxicity) will likely require additional safety measures/barriers to assure a safe design. This should also be further evaluated.

Safety and permitting

The increased safety and environmental risk when shifting from LNG to ammonia will require further evaluation on a situation basis. Due to the toxicity of ammonia the safety contours will increase significantly and the risk assessment and permit need to be re-evaluated. Furthermore, the potential increase of ammonia volumes could require a revision of regulations which were originally not adapted to potential future volumes.

A: Escajadillo, E. (2022, January 25). Germany progresses policy on 2043 LNG terminal conversions for hydrogen imports. ICIS Explore.

B: Fraunhofer, Conversion of LNG Terminals for Liquid Hydrogen or Ammonia, 2022

C: Black&Veatch, Hybrid LNG & Ammonia Infrastructure: Key to a Green Economy, E-book

3. **Terminal benefits** Terminal specific benefits

Methanol

Methanol is already a globally traded commodity and is closer to the petrochemical sector than to import of LNG. It is classified as a class IB liquid. Other IB liquids are ethanol, hydrocarbon fuels such as gasoline and kerosene, and reactants such as benzene, acetone, and toluene. Methanol is transported, imported and stored in bulk and good practices for safety are developed. Although the handling of methanol is less complex compared to LNG, there are still significant considerations that should be taken into account when repurposing and LNG terminal.

Design

Storage of methanol does not require any insulation as it is still liquid below 65 ^{o}C. According to the methanol institute[A] nickel alloys with 3% nickel are compatible with methanol to prevent corrosion but are specified for valves. Higher percentage nickel steels (9% with most LNG terminals) are therefore expected to be suitable but it should be evaluated to which extend it is also suitable for storage tanks. The only limitations with storing methanol in an LNG storage tank are the increased weight and the prevention of flammable gasses.

- The volumetric energy density of methanol is roughly 30% lower compared to LNG which reduces the storage capacity of a storage tank. Furthermore, the liquid density of methanol is 60% higher which further reduces the storage capacity if the structure and foundations are not reinforced. A total reduction to ~40-50% of energy storage capacity compared to LNG is expected.

- Empty voids in methanol storage should be avoided as they can fill with a flammable gas mixture and to avoid moisture extraction of ambient air. Methanol storage tanks with variable volume are therefore usually equipped with a floating rooftop or with a nitrogen blanket.

Due to the difference on handling and storing methanol compared to LNG, many other components are not needed anymore or will need to be replaced.

- The BOG and vaporizer are not needed anymore as there is no boil-off with methanol and gasification and further transport/use in gas form is also unlikely.

- The pumps however will need replacement due to the higher density of methanol compared to LNG.

- It is unknown if the metering package will still be suitable or if recalibration is possible.

- Safety systems will likely also require adaptations.

Safety and permitting

Overall, the safety risk profile for methanol will likely be lower compared to LNG as it will remain as a fluid when leaked. Toxicity of methanol should however be considered. Leakage of methanol in the environment can therefore be harmful but is quickly biodegradable (within days) and easily mixes and dilutes in water.

A: Methanol institute, Compatibility of Metals & Alloys in Neat Methanol Service, 2016

3. Terminal benefits Terminal specific benefits

Hybrid import

With the hybrid use of LNG terminals, multiple commodities will be imported at the same terminal. Here it is considered infeasible to use the same tanks and other components for multiple commodities due to the considerations provided in the earlier sections and the risk of contamination between commodities. The focus is therefore on terminals that have multiple tanks.

A terminal with multiple tanks can repurpose one or more tanks to another commodity while the other tanks will keep importing LNG. When LNG import declines, more storage tanks can be repurposed. This allows for security of supply for LNG while flexibility is provided to the development of the other energy import pathways. Technically this is considered feasible with the restrictions provided earlier (adaptation and replacement of some components) but will require separated processing.

Design

- Many LNG terminals have multiple storage tanks connected to a shared BOG and vaporizer. In such cases the processes should be separated when converting one or more tanks to another commodity. A dedicated BOG and vaporizer should be built for the new commodity. This will likely only be the case for LH2 as ammonia might not and methanol and LOCH will not require these process steps.

- At the ship interface there will also be a need for separated equipment. The “structural” parts of the jetty can likely serve multiple commodities but the piping and the connections will need to be adapted and separated. Concerns on material suitability were already discussed which should be taken into account. Furthermore, the piping at an LNG terminal is usually continuously cooled to avoid temperature stresses and deformation. This is usually done by recirculating LNG from the storage tank though the piping. In the case of multiple commodities, with for example liquid hydrogen, this cannot be done as there are significant temperature differences. Furthermore, the connections between LNG, LH2, Ammonia, methanol or other commodities will be different.

  For each commodity dedicated connection and piping is needed and it should be evaluated if the jetty can still support multiple connection and piping systems. It is therefore mainly the location, the dock and the jetty that can be shared.

Safety and permitting

- Finally, the safety and environmental aspects should be studied further. As mentioned earlier, risk profiles will likely increase with importing LH2 or ammonia. With hybrid terminals additional attention should be given to any domino effects. The presence of LH2 or Ammonia storage tanks might also require adaptation to safety barriers and design of the LNG storage tank.

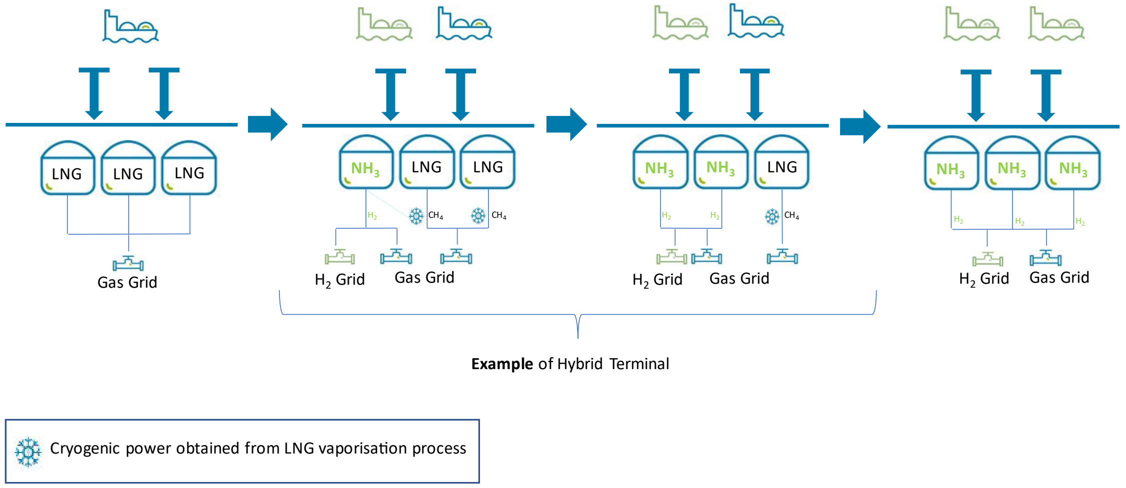


Figure: Example of different stages of hybrid import terminals,

Source: Enagás

3. Terminal benefits Terminal specific benefits

LOHC, e- and bio-methane

LOHC

LOHC (toluene based) shares much of the same characteristics as methanol. The considerations when converting an LNG terminal to a methanol terminal therefore also apply to LOHC. While the safety risk profile might be lower, the energy storage capacity will be reduced even further to ~20% compared to LNG due to lower energy density and higher weight.

Where methanol can be used directly, LOHC will require dehydrogenation (remove H2 from the carrier), post treatment and storage of hydrogenated and dehydrogenated carrier (Toluene). This should be considered in the conversion of an LNG terminal to LOHC as it will require additional space.

E-/bio-methane

The characteristics of liquified e-/bio-methane are expected to be similar to LNG and can therefore directly be imported through LNG terminals.

A: Methanol institute, Compatibility of Metals & Alloys in Neat Methanol Service, 2016

3. Terminal benefits Terminal specific benefits

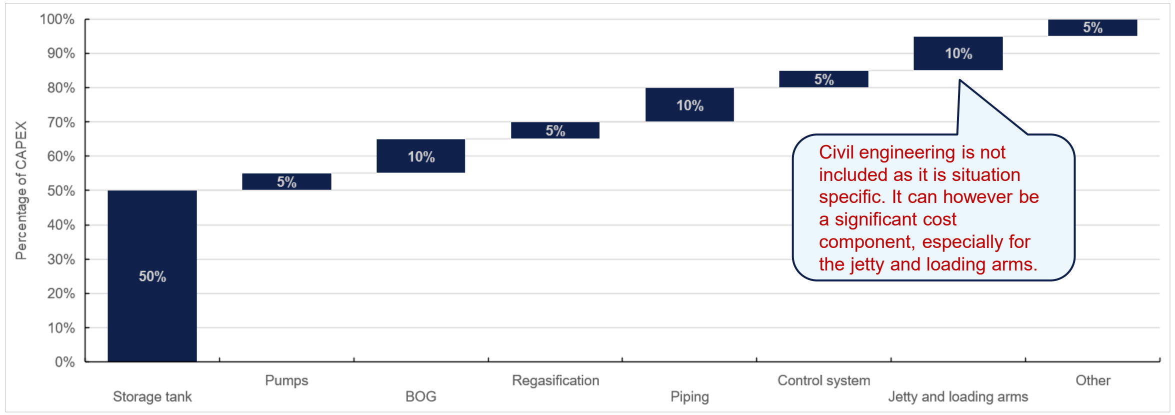
Potential cost savings

Based on the technical assessment (design, safety and environment), some components are suitable or can be adapted for other carriers than LNG. This means that in the case of a commodity transition, potential cost savings could be achieved. A CAPEX breakdown of an LNG terminal is provided on the right and provides the contribution for the different main components discussed in the previous sections. To estimate the potential CAEPX savings compared to a greenfield terminal, the following assumptions were made:

- It is assumed that the CAPEX and break-down of import terminals for other carriers is comparable to an LNG terminal. Site specific civil engineering is not included here, which could be a considerable cost component.
- The jetty and loading arms could contribute to substantial cost savings but are highly site-specific and thus uncertain.
- The methodology assumes the following to obtain potential cost savings:

Level of adaptation	Example	Rating	Potential CAPEX saving
No adaptations	-	H	100%
Small adaptation	Exchange of gaskets	H/M	75%
Large adaptations	large sub-components are to be replaced/adapted, e.g. pipe supports	M	50%
Significant adaptations	Replating of tank wall	M/L	25%
Adaptations are not possible	-	L	0%

There is a large dependency on the suitability of the storage tank material which causes a wide spread of potential costs savings. If the material is suitable, most of the terminal CAPEX can be saved.



Estimate of CAPEX breakdown of an LNG terminal [source: DNV]

Potential CAPEX saving (% of total terminal CAPEX)	E-/bio-methane	LH2	NH3	Methanol	LOHC
Storage tank	50	0 - 37.5	12.5 - 37.5	25 - 37.5	25 - 37.5
Pumps	5	0	0	0	0
BOG*	10	0 - 5	10	Not applicable	Not applicable
Regasification*	5	0 - 2.5	5	Not applicable	Not applicable
Piping	10	0	0	5	5
Control and safety system	5	0	0	0	0
Jetty and loading arms**	10	2.5 - 5	2.5 - 5	2.5 - 5	2.5 - 5
Other	5	0	0	0	0

*The BOG and regasification are probably not required for Methanol or LOHC
**Potential CAPEX savings for the jetty and loading arms are highly site-specific (e.g., water depth). Site specific civil engineering is not included here, which could be a considerable cost component.

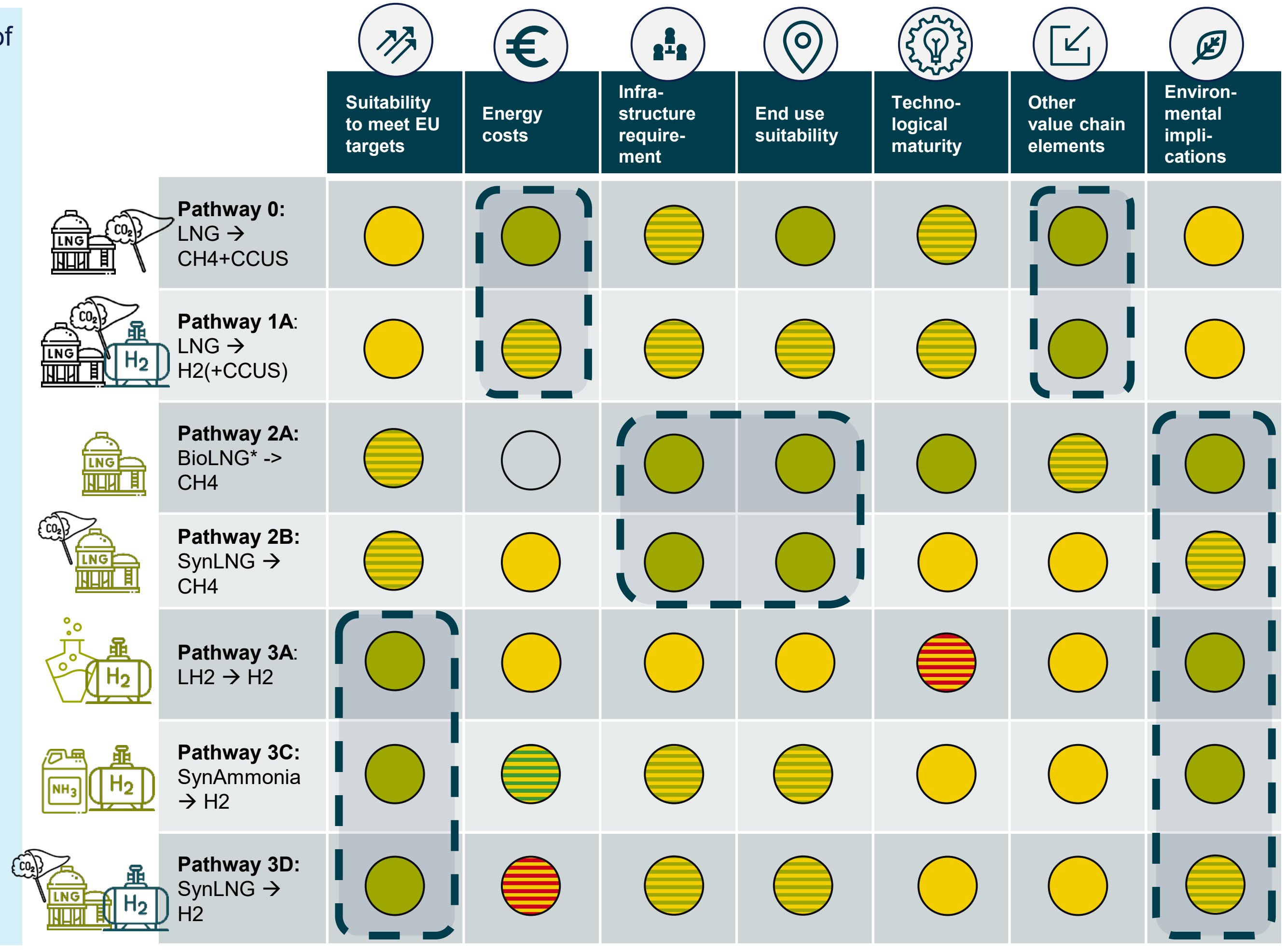
Chapter 4. Comprehensive assessment of pathways for the import of renewable and low-carbon gases

frontier economics

4. Assess pathways Results

Key take aways of the pathway assessment

- Different pathways have **different "strengths"** depending on the weighting of criteria – and **clusters** of pathway strength emerge
  - Pathways with **downstream greening** (LNG based pathways in combination with CCUS) are cost efficient and compatible with existing infrastructure and value chains, but might not directly contribute to H2 targets and depend on CCUS availability
  - Pathways with **upstream greening** have stronger suitability for EU targets and can be preferred from environmental perspective, but are not as cost-efficient and rely on new upstream value chains (incl. uncertainties around volumes for biomethane)
    - Pathways with upstream greening and **CH4 end use** have strengths in their compatibility with existing infrastructure and existing end use applications
    - Pathways with upstream greening and **H2 end use** have strengths in their contributions to EU H2 targets and H2 ramp-up, with uncertainties around technological maturity and potentially narrower scope for end use applications
- The combination of **diversity** of pathways with the **independence** and **flexibility** of individual terminal infrastructure across the EU to transition to low carbon energy is a key strength, meaning that:
  - Terminal infrastructure can contribute to the transition depending on **contemporary** and **local/regional needs**, for example in early phase CH4 may be required to maintain SoS while the eventual carrier is H2
  - Hence terminal infrastructure can facilitate a gradual (terminals can transition independently), **non-uniform** (the transition might need different energy (carriers) in different regions) and **secure transition** (some terminals can e.g. provide CH4 while others provide H2)
- While analysis does not reflect market price estimations or policy mechanisms, the IRA could support upstream greening pathways from US, while CBAM should in principle have no impact



Legend: Clusters of pathway advantages

- Overall positive assessment of pathway specifics
- Mixed factors identified in the assessment of pathway specifics
- Challenges identified in the assessment of pathway specifics

* Energy costs not quantified due to high uncertainty around availability and corresponding costs/prices of feedstock.

Icon sources credited in the annex.

4. Assess pathways Overview

Task overview: criteria-based assessment of the different pathways of interest

Fit for many

- **Objective**: This chapter offers a **comprehensive assessment of the potential maritime import pathways** for importing climate-neutral energy, reflecting quantitative results as part of this study and qualitative considerations.
- **Approach**: The key maritime import pathways are assessed against a set of criteria that strive to reflect the most relevant considerations.
  - The assessment builds on analyses and inputs from Chapters 1, 2 and 3 of this study.
- The remainder of **this chapter** offers a discussion of each pathway against each of the criteria.

	Suitability to meet EU targets	Energy costs	Infra-structure require-ments	End use suitability	Techno-logical maturity	Other value chain elements	Environ-mental impli-cations
Pathway 0: LNG → CH4+CCUS							
Pathway 1A: LNG → H2+CCUS							
Pathway 2A: BioLNG* -> CH4							
Pathway 2B: SynLNG → CH4							
Pathway 3A: LH2 → H2							
Pathway 3C: SynAmmonia → H2							
Pathway 3D: SynLNG → H2							

Suitability to meet EU targets: Consideration of EU targets/demand (volumes) for emission reduction and green carriers, building on chapter 1

Energy costs: Assessment of fundamental costs of imported energy for different pathways, reflecting the results from chapter 2.

Infrastructure requirements: This criterion considers costs and benefits of existing (downstream and upstream) infrastructure, such as terminals, based on results from chapter 3

End use suitability: Suitability for breadth of end-use purposes, depending on end-use sector and infrastructure development.

Technological maturity: Technological maturity, including scalability and time to market in light of the envisaged timeline for EU imports, based on results from chapter 3

Other value chain elements: Considerations on value chain elements outside and in the EU, differentiating whether these exist vs. need to be newly established.

Environmental implications: Environmental considerations, including carbon content and residual emissions of the respective technologies and pathways

Icon sources credited in the annex.

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4. **Assess pathways** EU target suitability

While all pathways contribute to emission reductions, not all contribute to EU H2 targets

	Suitability to meet EU targets / demand
Pathway 0: LNG → CH4+CCUS	Pathway has the potential to contribute significantly both to low carbon energy volumes and to emission reductions, particularly in large scale applications where CCUS can be applied. Pathway does not contribute to the renewable targets as defined in the RePower EU and RED III.
Pathway 1A: LNG → H2(+CCUS)	Pathway has the potential to contribute significantly to low carbon energy volumes, to emission reductions and to the EU hydrogen ramp-up, as potentially large volumes of low carbon H2 can be realised relatively short-term. Pathway does not contribute to the renewable targets as defined in the RePower EU and RED III.
Pathway 2A: BioLNG -> CH4	Quick and effective contribution to emission reductions through climate neutral energy volumes, however, the scaling potential could be lower than for H2 based pathways in the long-term. BioLNG a relevant carrier for short-term emission reduction and for applications, which continue to rely on (climate neutral) CH4 in the long-term (e.g. as feedstock, potentially remaining (green) methane grids).
Pathway 2B: SynLNG → CH4	Quick contribution to emission reduction possible with current infrastructure and transition into H2 conversion (Pathway 3D) feasible. Targets within RePower EU plan include derivatives, so green CH4 can make a relevant contribution.
Pathway 3A: LH2 → H2	Very good suitability with EU targets for emission reductions and hydrogen ramp-up, high acceptance of carrier characteristics and large scaling possible, but rather in the long-term due to limited experience with the carrier - timeline of feasibility is uncertain.
Pathway 3C: SynAmmonia → H2	Very good suitability with EU targets for emission reductions and hydrogen ramp-up: recent studies suggested a focus on ammonia as an H2 carrier (industry experience, direct use in industry).
Pathway 3D: SynLNG → H2	Very good suitability with EU targets for emission reductions and hydrogen ramp-up and compatibility with existing maritime transport infrastructure as it is based on an existing carrier (technology).

Legend: Comparison of pathways relative to each other
- Strength of pathway
- Mixed factors
- Weakness of pathway

Icon sources credited in the annex.

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4. Assess pathways Energy costs

The pathways are associated with differences in their energy costs

		Energy costs
Pathway 0: LNG → CH4+CCUS	Strength of pathway	Low costs. Sensitive to development of carbon costs and methane prices. Potential cost savings through coldness utilisation, released at re-gasification, for CO2 liquefaction.
Pathway 1A: LNG → H2(+CCUS)	Strength of pathway / Mixed factors	Low costs. Main cost driver is methane reforming (ATR or SMR), apart from costs for carbon and methane. Potential cost savings through coldness utilisation, released at re-gasification, for CO2 liquefaction.
Pathway 2A: BioLNG -> CH4		*Not quantified due to high uncertainty around availability and corresponding costs/prices of feedstock.*
Pathway 2B: SynLNG → CH4	Mixed factors	Apart from LCOH, methanation (incl. large range for costs for carbon depending on availability – biogenic CO2 an option) is the main cost driver. In the long-term cost savings might be enabled through a closed carbon loop or "negative emissions" with biogenic CO2 usage.
Pathway 3A: LH2 → H2	Mixed factors	Main cost drivers are (local) costs of hydrogen production, H2 liquefaction and LH2 transport, with large uncertainty about future costs (due to low technological maturity of LH2 storage and lack of industry experience). Potential cost savings through coldness utilisation, released at re-gasification, for other industry processes.
Pathway 3C: SynAmmonia → H2	Strength of pathway / Mixed factors	Main cost drivers are (local) costs of hydrogen production, upstream Haber Bosch and downstream re-transformation of Ammonia to H2 (cracking). The last step is associated with both high costs and the highest cost uncertainty – however, it can be avoided when Ammonia is used directly as an industry input without .
Pathway 3D: SynLNG → H2	Mixed factors / Weakness of pathway	High costs, driven by high costs of methanation (incl. large range for costs for carbon depending on availability – biogenic CO2 an option) and then downstream methane reforming (ATR or SMR). In the long-term cost savings might be enabled through a closed carbon loop (also, coldness utilisation for CO2 liquefaction) or "negative emissions" with biogenic CO2 usage.

Legend: Comparison of pathways relative to each other

- Strength of pathway
- Mixed factors
- Weakness of pathway

Icon sources credited in the annex.

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4. Assess pathways Infrastructure requirement

All pathways rely on the terminal infrastructure – some of them require repurposing

		Infrastructure requirements (terminal and downstream)
Pathway 0: LNG → CH4+CCUS	Mixed factors / Strength	No terminal adjustments required, relying on the existing CH4 infrastructure. Development of carbon infrastructure required for CCUS.
Pathway 1A: LNG → H2(+CCUS)	Mixed factors	No terminal adjustments required, relying on the existing CH4 infrastructure. Development of hydrogen transport infrastructure required for remote (i.e. not at/near terminal site) H2 use. Carbon infrastructure required for CCUS. Installation of ATR.
Pathway 2A: BioLNG -> CH4	Strength of pathway	Neither terminal adjustments nor other downstream infrastructure adjustments required, relying on existing CH4 infrastructure.
Pathway 2B: SynLNG → CH4	Strength of pathway	Neither terminal adjustments nor other downstream infrastructure adjustments required, relying on existing CH4 infrastructure.
Pathway 3A: LH2 → H2	Mixed factors	Technology and proven/accepted standards are not yet in place but experience from other industries on designing and handling liquid hydrogen could provide some guidance. The novelty of designing terminals for liquid hydrogen will therefore add challenges but might also lead to conservatism with regard to design and use of materials[1].
Pathway 3C: SynAmmonia → H2	Mixed factors / Strength	Existing design practices and experience in building and operating such terminals can be used to expand the import pathway of H2 through ammonia. LNG terminals can be repurposed with cost savings to ammonia.[2] Development of downstream transport infrastructure required for remote (i.e. not at/near terminal site) ammonia/H2 use. Concerns regarding safety and environment should be further evaluated.
Pathway 3D: SynLNG → H2	Mixed factors / Strength	No terminal adjustments required, relying on the existing CH4 infrastructure. Development of hydrogen transport infrastructure required for remote (i.e. not at/near terminal site) H2 use. Installation of ATR.

1 – Fraunhofer (2022): Conversion of LNG Terminals for Liquid Hydrogen or Ammonia
2 - Riemer, M.; Schreiner, F.; Wachsmuth., J. (2022): Conversion of LNG Terminals for Liquid Hydrogen or Ammonia. Analysis of Technical Feasibility und Economic Considerations.
3 - Black&Veatch, Hybrid LNG & Ammonia Infrastructure: Key to a Green Economy

Legend: Comparison of pathways relative to each other
- Strength of pathway
- Mixed factors
- Weakness of pathway

Icon sources credited in the annex.

4. Assess pathways End-use suitability

Depending on their end-use and infrastructure development, different timelines of suitability arise

	End-use suitability
Pathway 0: LNG → CH4+CCUS	**CH4 –** suited for all existing applications, no adjustments of final demand applications required
Pathway 1A: LNG → H2(+CCUS)	**H2** – H2 (and derivates) suited for most end use applications, in particular in industry and hard to abate sectors. Pathway entails optionality to initially (temporarily) use CH4+CCUS, which is primarily suitable for high volume applications, e.g. in specific industries or power plants.
Pathway 2A: BioLNG -> CH4	**CH4 –** suited for all existing applications, no adjustments of final demand applications required
Pathway 2B: SynLNG → CH4	**CH4 –** suited for all existing applications, no adjustments of final demand applications required
Pathway 3A: LH2 → H2	**H2** – H2 (and derivates) suited for most end use applications, in particular in industry and transport
Pathway 3C: SynAmmonia → H2	**H2** – H2 (and derivates) suited for most end use applications, in particular in industry and transport. Pathway entails optionality to employ ammonia in end-use ammonia. Ammonia also suited for end use applications in industry, transport and agriculture.
Pathway 3D: SynLNG → H2	**H2** – H2 (and derivates) suited for most end use applications, in particular in industry and transport. Pathway entails optionality to initially (temporarily) use SynCH4, which is suitable for all existing methane applications, e.g. in households, buildings and industry.

Legend: Comparison of pathways relative to each other
- Strength of pathway
- Mixed factors
- Weakness of pathway

Icon sources credited in the annex.

4. Assess pathways Technological maturity

There are numerous elements across the value chains of the pathways that must still gain maturity

	Technological maturity
Pathway 0: LNG → CH4+CCUS	Maritime and domestic LNG/CH4 transport is mature. Currently there is limited experience and maturity of CCU, but more experience and maturity of CCS (e.g. linked to Enhanced Oil Recovery, EOR).
Pathway 1A: LNG → H2(+CCUS)	Maritime and domestic LNG/CH4 transport is mature and SMR is an established process. Currently there is limited experience and maturity of CCU, but more experience and maturity of CCS (e.g. linked to Enhanced Oil Recovery, EOR).
Pathway 2A: BioLNG -> CH4	Established processes along the entire value chain
Pathway 2B: SynLNG → CH4	High volume of upstream carbon use for methanation (point capture or direct air capture) with limited industrial experience; methanation not commercially tested at large scale[2]
Pathway 3A: LH2 → H2	Technology (esp. storage) and proven/accepted standards are not yet in place but experience from other industries on designing and handling liquid hydrogen could provide some guidance. The novelty of designing terminals for liquid hydrogen will therefore add challenges but might also lead to conservatism with regard to design and use of materials.[1,2] Downstream H2 transport and use sufficiently mature.
Pathway 3C: SynAmmonia → H2	NH3-Cracker not technologically mature yet, first large-scale plants expected as of 2030 (not required for direct end use of ammonia – technologically mature value chain)[2]
Pathway 3D: SynLNG → H2	High volume of upstream carbon use for methanation (point capture or direct air capture) with limited industrial experience; methanation not commercially tested at large scale.[2] Downstream H2 transport and use sufficiently mature.

1 - Riemer, M.; Schreiner, F.; Wachsmuth., J. (2022): Conversion of LNG Terminals for Liquid Hydrogen or Ammonia. Analysis of Technical Feasibility und Economic Considerations. Karlsruhe: Fraunhofer Institute for Systems and Innovation Research ISI.
2 - Agora Industrie und TU Hamburg (2023): Wasserstoff-Importoptionen für Deutschland. Analyse mit einer Vertiefung zu Synthetischem Erdgas (SNG) bei nahezu geschlossenem Kohlenstoffkreislauf.

Legend: Comparison of pathways relative to each other
- Strength of pathway
- Mixed factors
- Weakness of pathway

Icon sources credited in the annex.

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4. Assess pathways Other value chain elements

Outside of the EU, some pathways require a build-up of a long value chain

Pathway	Other value chain elements
Pathway 0: LNG → CH4+CCUS	Limited to no reliance on new value chains outside EU. CBAM should not have a direct cost impact administrative burden depends on eventual treatment of LNG imports, which are designated for CCUS.
Pathway 1A: LNG → H2(+CCUS)	Limited to no reliance on new value chains outside EU. CBAM should not have a direct cost impact administrative burden depends on eventual treatment of LNG imports, which are designated for CCUS.
Pathway 2A: BioLNG -> CH4	Some reliance on new value chains outside EU with potentially competition for use case of (limited) bio feedstock.
Pathway 2B: SynLNG → CH4	Upstream greening: Reliance on new value chains outside EU for SynLNG production. Relies on standards for non-EU products (e.g. definition of green energy) or even internationally coordinated carbon schemes (e.g. certification, measurement). US IRA could support pathway, by supporting upstream emission reduction (technologies).
Pathway 3A: LH2 → H2	Upstream greening: Reliance on new value chains outside EU for LH2 production. Relies on standards for non-EU products (e.g. definition of green energy). US IRA could support pathway, by supporting upstream emission reduction (technologies).
Pathway 3C: SynAmmonia → H2	Upstream greening: Reliance on new value chains outside EU for SynAmmonia production. Relies on standards for non-EU products (e.g. definition of green energy). US IRA could support pathway, by supporting upstream emission reduction (technologies).
Pathway 3D: SynLNG → H2	Upstream greening: Reliance on new value chains outside EU for SynLNG production. Relies on standards for non-EU products (e.g. definition of green energy) or even internationally coordinated carbon schemes (e.g. certification, measurement). US IRA could support pathway, by supporting upstream emission reduction (technologies).

Legend: Comparison of pathways relative to each other
- Strength of pathway
- Mixed factors
- Weakness of pathway

Icon sources credited in the annex.

4. Assess pathways Environmental implications

Some pathways might enchain residual emissions that would need compensatory measures

Pathway		Environmental implications
Pathway 0: LNG → CH4+CCUS	Mixed factors	Residual CO2 emissions: Open questions remain around political and public acceptance of compensation mechanisms
Pathway 1A: LNG → H2(+CCUS)	Mixed factors	Residual CO2 emissions: Open questions remain around political and public acceptance of compensation mechanisms
Pathway 2A: BioLNG -> CH4	Strength of pathway	Carbon neutral pathway (potentially carbon negative if CCU was applied in addition)
Pathway 2B: SynLNG → CH4	Mixed factors (striped)	Climate neutral energy, but with carbon element required for transport: Closed carbon cycle or upstream carbon sources (point source or air capture), which compensates downstream CO2 release. Fully green with a biogenic carbon source.
Pathway 3A: LH2 → H2	Strength of pathway	No carbon involved along the value chain
Pathway 3C: SynAmmonia → H2	Strength of pathway	No carbon involved along the value chain
Pathway 3D: SynLNG → H2	Mixed factors (striped)	Climate neutral energy, but with carbon element required for transport: Closed carbon cycle or upstream carbon sources (point source or air capture), which compensates downstream CO2 release. Fully green with a biogenic carbon source.

Legend: Comparison of pathways relative to each other
- Strength of pathway
- Mixed factors
- Weakness of pathway

Icon sources credited in the annex.

Chapter 5. Policy recommendations

5. Policies Background

The key contributions serve as the basis for identifying barriers and policy recommendations.

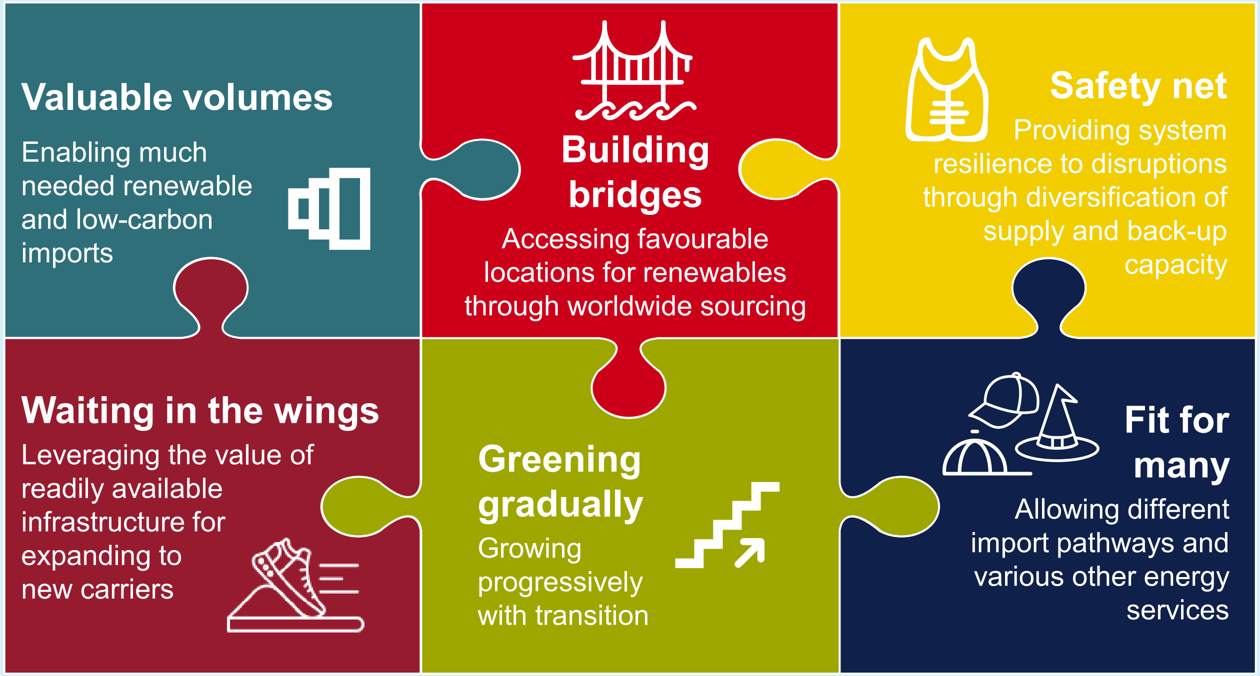
How do terminals and terminal operators as infrastructure providers contribute towards EU challenges and objectives?

We have identified **six contributions** from terminals and their role in the future energy system.

In the **following** we:

- Consider regulatory treatment in 4th gas package and remaining open questions
- Outline barriers for terminal infrastructure operators on their path towards renewable and low-carbon energy imports
- Describe **policy recommendations** that will support the realisations of the contributions from terminals

Rationale for policy recommendations:
Unlock contributions from terminal infrastructure.



Icon sources credited in the annex.

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5. Policies Identifying barriers and threats

Barriers and threats that might impede the terminal contributions to the EU objectives…

Barriers and threats identified

Terminal infrastructure regulation

- Remaining **uncertainty of MS/NRA implementation** of EU regulation raises risk levels of investments
- Restricted **definition of hydrogen terminal** activity prevents level playing field, curbs multi-molecule terminals
- **Restraint regulatory rules**, neglecting other activities, can complicate emission reduction

Policy environment for terminals

- Inconsistent **planning** slows down transition and prevents efficient use of infrastructure
- Technological **immaturity** of value chain elements and lack of supportive policies
- High process and admin **costs** for non-LNG energy imports
- Slow transition due to lengthy and granular **permission processes**

Upstream supply value chain / policy

- Losing import potentials through restraint **carrier** consideration
- Underdeveloping **sourcing** flexibility risks high dependency on certain carriers and countries
- Frictions in international value chains through lacking **standards**

Downstream markets / policy

- Chicken-egg **hold-up** in end-use adjustments for H2
- Miscoordination in end-use **planning**, duplicating efforts
- Overly narrow policy focus, disregarding development of certain markets

… lead to policy recommendations for each of these barriers.

5. **Policies** Gas infrastructure regulation

The 4th Gas Package has defined the EU regulation for H2/ammonia terminals

Background on natural gas / LNG (3rd Gas Package)

- In current EU regulation (3rd Gas Package), LNG terminals are per default regulated, including regulated Third-Party-Access (**rTPA**)
- Motivation for rTPA was to prevent horizontal market power and vertical foreclosure and thus **enable up- & downstream competition**
- Because rTPA may pose asymmetric risks to investors, in 2003 the option for case-by-case **exemptions** for new infrastructure has been introduced, which many LNG terminals have used since then

Horizontal unbundling

- Horizontal unbundling of LNG and "hydrogen terminals" come with intention to **avoid cross-subsidies** between these activities and thus **enable market entries** of non-LNG operators to foster competition
- However, this can come at cost of **undermining synergies**, particularly for hybrid terminal business models and emerging markets

TPA for renewable & low-carbon gas terminals

- Particularly in the ramp-up phase with a limited number of REN & LC terminals, a non-discriminatory (r)TPA can help to increase **accessibility** to global markets and thus **increase competition** and **security of supply**
- At the same time, (some) investors may prefer **risk mitigation** measures such as long-term fixed/indexed price contracts or vertical integration (e.g. oil companies) that may not be in line with standard EU regulation / rTPA (nTPA does not rule out long-term contracts)
- The net benefit of different TPA rules is likely to **vary over time and between MS** (e.g. depending on market maturity)

4th Gas Package

- The package entails negotiated Third-Party-Access (**nTPA) for "hydrogen terminals"** (= LH2 & ammonia, no other H2-derivatives) and **horizontal accounting unbundling** across different carriers in terminals
- An option for **exemption** from the general regulatory rules exists for new terminals

Some barriers and threats remain…

- Remaining uncertainty of MS/NRA implementation of regulation raises risk levels of investments
- Restricted **definition of hydrogen terminal** activity prevents a level playing field across hydrogen carriers
- Restraint regulatory rules, neglecting other activities, can complicate emission reduction

5. **Policies** Terminal infrastructure regulation

We have identified policies for the regulatory environment of terminal infrastructure

Barriers and threats	Recommendations
Remaining uncertainty of MS/NRA implementation of regulation raises risk levels of investments	• Regulation has been specified on EU level, but implementation from **MS/NRAs** pending. MS/NRAs could go beyond EU regulation in their implementation but should carefully assess reasons for doing so. • There is value in maintaining accounting unbundling as the maximum level of horizontal unbundling for carrier-specific activities (e.g. LNG and H2) to allow for operational synergies and ensure a timely transition of terminals. • Establish **certainty on policy and regulation:** ensure an adequate, effective and timely implementation of the Green Deal and finalise remaining dossiers, including associated delegated and implementing acts. Integrate and recognise the role of terminals in the upcoming energy policy (2040 targets, energy system integration, etc.).
Restricted definition of hydrogen terminal activity prevents a level playing field and curbs multi-molecule terminals	• Regulations should allow for **multi-molecules** / multi-asset sites to enable synergies and wider economic benefits • The definition of hydrogen terminal activity is currently restricted to LH2 and ammonia which is injected into the grid. • To ensure a **level-playing field** across actors and activities and avoid regulatory inconsistencies, it requires a careful assessment whether this definition should include other renewable carriers which can serve as substitutes for green energy imports, like SynLNG, green methanol and LOHC.
Restraint regulatory rules, neglecting other activities, can complicate emission reduction	• The regulatory rules (in particular horizontal and vertical unbundling requirements) need to reflect and allow (also in outstanding implementations of the MS) that terminals will not act as import-only providers in the future, but instead 1) perform other energy system services (e.g. truck/ship (re)loading, virtual liquefaction) and 2) facilitate new markets and emission reduction pathways (e.g. acting as carbon transport hubs).

5. Policies Policy environment for terminals

We have identified policies enhancing the system efficiency of terminal infrastructure

Barriers and threats	Recommendations

Inconsistent planning slows down transition and prevents efficient use of infrastructure	• **Align and coordinate on national and EU legislation** on transformation pathways and timelines to take potential contributions of terminals into account, reflecting variation in pathways and timelines across MS and terminals
	  • **Involve terminal operators in planning processes**, also for downstream EU infrastructure.
	  • Include **resilience planning** in the emission reduction strategies, considering potential disruptions due to climate-related events or geopolitical factors.

Technological immaturity of value chain elements	• Measures to **support less mature technologies** across the value chain (e.g. financing of pilot projects, R&D, investments into innovation, potentially including hybrid terminals if there are non-private benefits such as increased SoS and decarbonisation) to enable cost reduction due to learning effects and spill-overs and realise public benefits (SoS, decarbonisation). • Timeline for such innovation support needs to be in line with economic developments, e.g. also with respect to some terminals repurposing in the 2030s. • An example is the **US IRA** which provides support to innovative clean energy technologies.
High process and admin costs for non-LNG energy imports	• **Unnecessary costs** can e.g. be avoided by **maintaining scalability of import value chain:** This can be supported, for example, by conducting a revision of existing standards and requirements (e.g. rules for ammonia not fit for large scale imports or transport). • Consider terminals as **energy hubs**, potentially also serving as flexibility sources for the electricity market, gas and hydrogen markets and as “export” sites (e.g. today LNG terminals for ship reloading, small-scale and truck loading)
Slow transition due to lengthy and granular permission processes	• **Speed up, harmonise and facilitate** project licensing and permitting (also for imports of carriers other than LNG) for terminal operators and reduce bureaucratic efforts. Allow for “hybrid permitting”, allowing for multiple molecules at the same terminal in one consolidated process.

5. Policies Policies aimed at upstream value chain

The transformation of terminal infrastructure needs adjusted upstream value chains

Barriers and threats	Recommendations
Losing import potentials through restraint carrier consideration	• Consider **different low-carbon energy carriers** across regulation and policies, including mechanisms such as H2Global (in its first window restricted to e-ammonia, e-methanol and e-kerosene) and European Hydrogen Bank • Overly constraint rules can complicate emission reduction efforts for private stakeholders, e.g. 2041 limit for non-biogenic CO2 in RFNBO/RCF could impede development of long-term investments/contracts, so that 2050 (being the target for climate-neutrality) could be considered
Frictions in international value chains through lacking standards	• **International certificates (e.g. globally coordinated guarantee of origin system) and standards** required to provide certainty to investors when taking investments at export/import terminals and to minimise compliance costs, in particular due to larger relevance of global value chain (e.g. rules for upstream greening, certification of bioLNG) • For example, constraint certification requirements of Union Database for Biofuels for imports from outside EU complicates international trade and imports.
Underdeveloping sourcing flexibility creates import dependencies	• Develop **strategic partnerships and cooperation** between the EU and **multiple exporting countries** / coordinate with international pillar of the European Hydrogen Bank. **Support pilot / large-scale production projects** in 3rd countries helping to kickstart and ramp up the renewable H2 (derivatives) import value chain. • However, maintain diverse approach to international cooperations and funding by avoiding a strong focus on singular regions (e.g. by limiting fund shares for certain regions) to achieve high **sourcing flexibility**. Otherwise, country dependencies can create supply bottlenecks.

5. **Policies** Policies aimed at downstream value chain

The transformation of terminal infrastructure requires reliable downstream markets

Barriers and threats	Recommendations

Chicken-egg hold-up in end-use adjustments for H2	• In the short to mid-term, **H2 injection should not be limited to an H2-only grid**, but ramp-up can e.g. benefit from
	  • Local/regional end use near electrolysers and terminals (largely independent of backbone/pipeline grid),
	  • Other means of transport to end-use than pipelines, and
	  • The option for blending, i.e. H2 injection in the methane grid in the ramp-up phase (different rules depending on member state considered).

Miscoordination in end-use planning, duplicating efforts	• Develop (national) **hydrogen adoption roadmaps** that outline the gradual integration of renewable and low carbon energy imports into the EU and infrastructure planning with involvement of numerous stakeholders, incl. terminal operators. • Not only H2 transition and infrastructure are important for future terminal operation, but also CO2 transport and storage transition and infrastructure.

Overly narrow policy focus, disregarding development of certain markets	• It is obligatory to consider **all potential future markets** to avoid stalling the development of certain markets due to lacking policy certainty.
	  • As an **example**, terminals could be an integral infrastructure element to future CO2 flows – however the **future developments of the CO2 market** could be accelerated by providing clarity on policy and standards for private entities to take binding (investment) decisions.
	  • This is equally true for any emerging industry that is not at the centre of today's policies.

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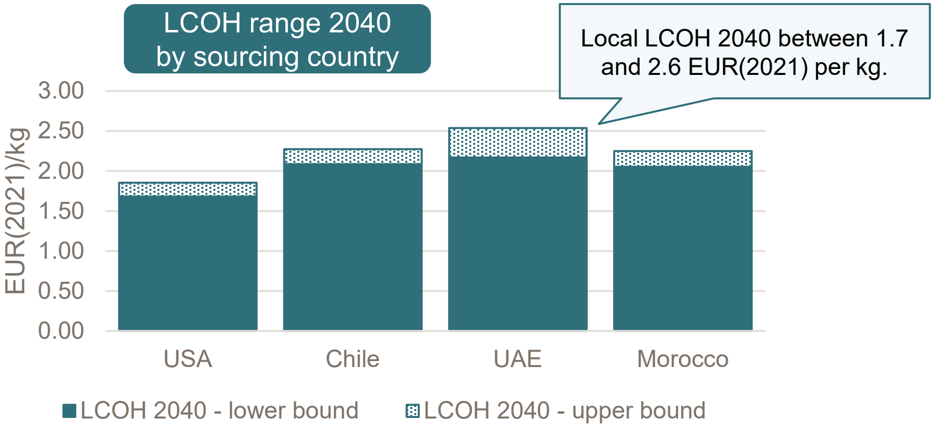
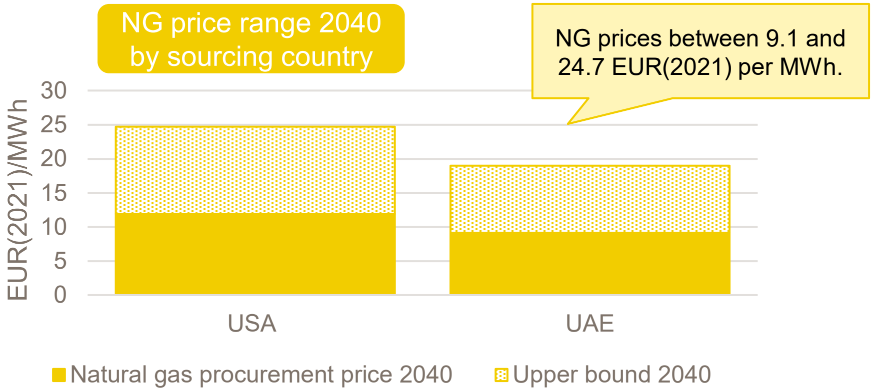
A.1: Appendix 1

Assumptions

2. Pathway costs 2040 Regional LCOH/NG prices

Background: We derive regional LCOE and LCOH for baseload supply for a representative location in each country through an optimisation model. We consider a methane price range.





Source: Frontier Economics

Key assumptions

Technology	CAPEX	2040	Other assumptions	Source
Wind Onshore	**860**	k EUR/MW	with OPEX **4%**(capex) p.a. & **25 years** depreciation	IEA(2022) , Braendle et al (2021)
PV	**340**	k EUR/MW	with OPEX **2.5%**(capex) p.a. & **25 years** depreciation	IEA(2022), Braendle et al (2021)
Electrolysis	**450-700**	k EUR/MW	with **OPEX 15,000 EUR/MW p.a.**, **20 years** depreciation, **71%** efficiency	IEA (2023a), Braendle et al (2021)

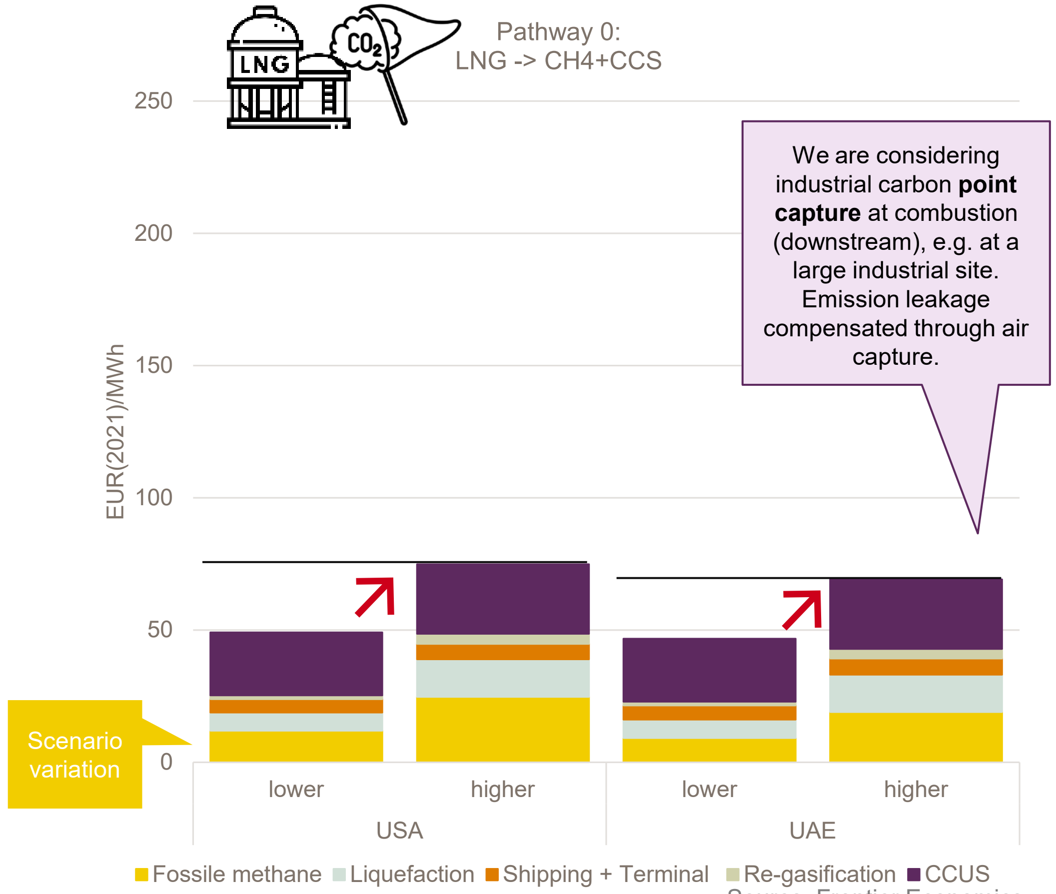
Scenario variation

Assumptions for hydrogen storage tanks, hydrogen storage in salt caverns, and battery storage can be found in the presentation annex. All EUR-figures are in real EUR-2021 terms. 60% re-electrification efficiency.

- LCOE 2040 between 39 and 49 EUR(2021) per MWh for the sourcing countries. Central-European LCOE 2040 (for downstream processed) of ca. 66 EUR(2021) per MWh.
- We **differentiate the WACCs for the LCOE/LCOH calculation** by sourcing country, reflecting country-specific risks/uncertainty for local investments.
  - USA: 5%, Chile 6%, UAE, 6%, Morocco 7%, based on Damodaran (2023).
- Moreover, we are assuming a **price range for natural gas procurement** in 2040 for the USA and UAE. We are not considering Morocco and Chile for the conventional LNG-pathways, as they are not natural gas exporters.
- For **natural gas**, we are considering the WEO 2023 STEPS scenario as a lower range, and information from the DNV database with a 25% lump-sum mark-up as an upper range.

2. Pathway costs 2040 Conventional LNG & downstream CCU at combustion

We consider USA and UAE as sourcing countries – and introduce a cost range to our estimates



Source: Frontier Economics

* Transformation losses are counted towards the associated technology.

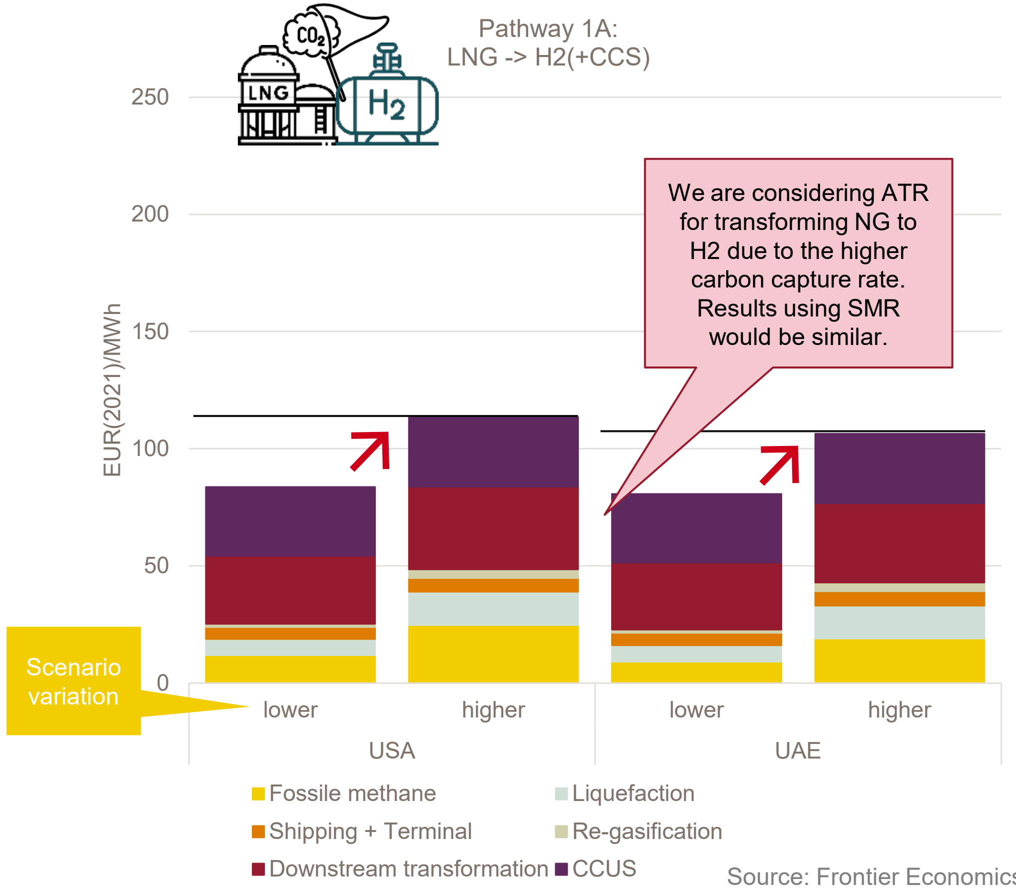
Key assumptions

2040 Technology		Scenario variation	Other comments	Source
NG liquefaction	300 – 717	EUR/kW(LNG)	with OPEX **4%**(capex) p.a. & **25 years** depreciation, **95%** efficiency, **0.5** MWh(el)/t(LNG)	Agora (2023), DNV, FVV (2022)
Shipping costs (excl. terminal and boil-off losses) – LNG ship	41 / 47	EUR/t(LNG), depending on sourcing country	Cost-based calculation of an LNG ship using transport distance. 41 EUR/t for USA, 47 EUR/t for UAE. Boil-off gas used as ship fuel.	Agora (2023)
Boil-off losses	0.16%	per day	Considered for the transport route + 5 days at import/export-terminal each.	Agora (2023)
Import + export-terminal & port costs	16.6	EUR/t(LNG)	(Un-)loading costs + costs for laytime.	Own assumption, based on tariff review
LNG re-gasification	64-192	EUR/kW(CH4)	with OPEX **4%**(capex) p.a. & **25 years** depreciation, **98.5%** efficiency	Agarwal (2020)
CO2 point capture – capture rate	90%	Scenario variation		IEA (2023c)
Point CO2 capture, transport, injection and storage	115	EUR/t CO2	Central estimate for Central Europe from cost-based approach using IEA (2023b), in line with unit costs shown in ENTEC (2023) and CATF (2023).	IEA (2023b), ENTEC (2023), CATF (2023).
Downstream DAC (to compensate leakage)	151-275	EUR/t CO2 (Scenario variation)	**10% leakage** compensated through air-capture. Local estimate for Central European LCOE.. Scenario variation through capex variation (**235-756** EUR/(t(C02) p.a.) and electricity requirement (incl. heat demand, **1.5 – 2.3** MWh(el)/t(CO2). Incl. a lump-sum 27 EUR/t CO2 for transport and storage.	Moritz et al. (2021), Brown + Hampp (2023)

All EUR-figures are in real EUR-2021 terms. NG carbon intensity 0.201 t CO2/MWh(CH4).

2. Pathway costs 2040 Conv. LNG to H2

Additional to pathway zero, we consider a centralised ATR unit to transform methane into hydrogen, using a downstream point capture for the carbon emissions



Source: Frontier Economics

* Transformation losses are counted towards the associated technology.

Key assumptions

2040 Technology	Scenario variation		Other comments	Source
NG liquefaction	300 – 717	EUR/kW(LNG)	with OPEX **4%**(capex) p.a. & **25 years** depreciation, **95%** efficiency, **0.5** MWh(el)/t(LNG) electricity demand	Agora (2023), DNV, FVV (2021)
Shipping costs (excl. terminal and boil-off losses) – LNG ship	41 / 47	EUR/t(LNG), depending on sourcing country	Cost-based calculation of an LNG ship using transport distance. 41 EUR/t is the value for USA, 47 EUR/t is the value for UAE. Boil-off gas used as ship fuel.	Agora (2023)
Boil-off losses	0.16%	per day	Considered for the transport route + 5 days at import/export-terminal each. Scenario variation	Agora (2023)
Import + export-terminal & port costs	16.6	EUR/t(LNG)	(Un-)loading costs + costs for laytime.	Own assumption, based on tariff review
LNG re-gasification	64-192	EUR/kW(CH4)	with OPEX **4%**(capex) p.a. & **25 years** depreciation, **98.5%** efficiency	Agarwal (2020)
ATR	920	EUR/kW(H2)	with OPEX **3%**(capex) p.a. & **20 years** depreciation, **80%** efficiency, **0.14** kWh(el)/kWh(H2) electricity requirement	Agora (2023)
ATR carbon capture rate	94-98%	Scenario variation		Agora (2023)
Point capture, transport, injection and storage	115	EUR/t CO2	Central estimate for Central Europe from cost-based approach using IEA (2023b), in line with unit costs shown in ENTEC (2023) and CATF (2023).	IEA (2023b), ENTEC (2023) , CATF (2023).
Downstream DAC (to compensate leakage)	151-275 Scenario variation	EUR/t CO2	**2-6% leakage** is compensated through equal amounts of air-captured carbon. Local estimate for Central European LCOE (downstream). Scenario variation introduced through capex variation (**235-756** EUR/(t(C02) p.a.) and electricity requirement variation (incl. heat demand, **1.5 – 2.3** MWh(el)/t(CO2). Incl. a lump-sum 27 EUR/t CO2 for transport and storage. .	Moritz et al. (2021), Brown + Hampp (2023), Agora (2023b)

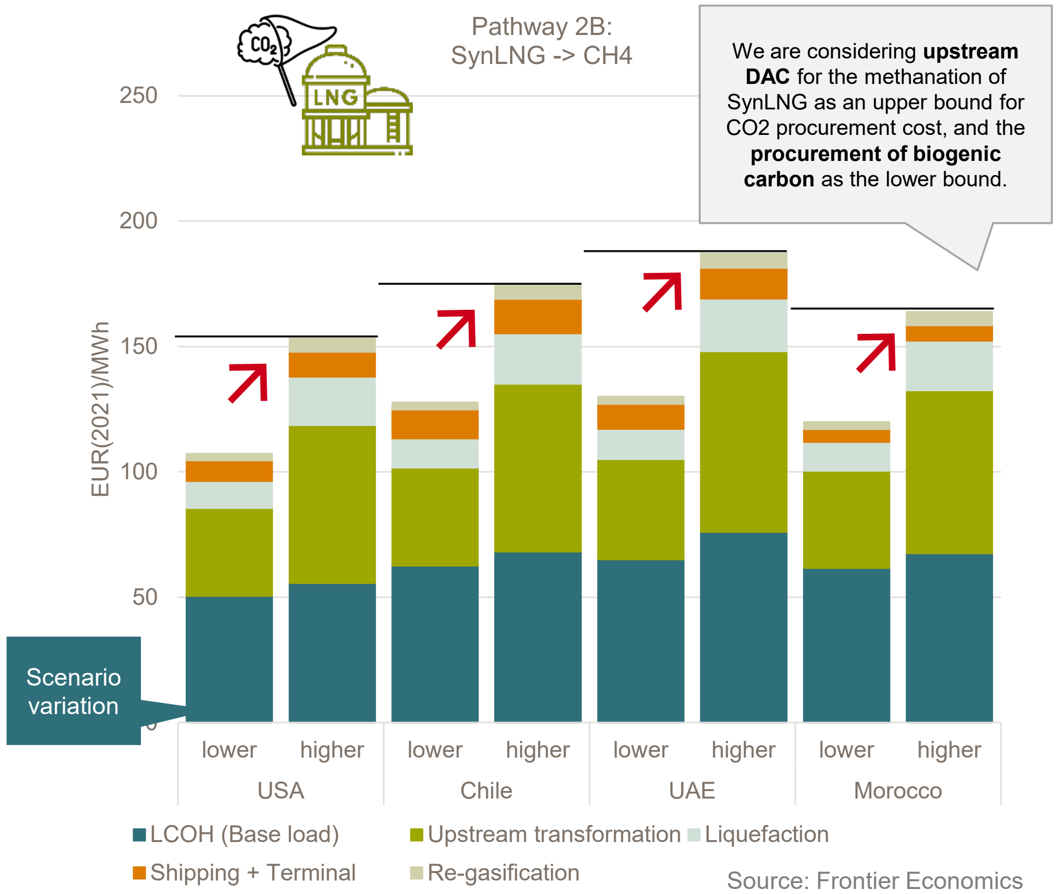
All EUR-figures are in real EUR-2021 terms. NG carbon intensity 0.201 t CO2/MWh(CH4).

Icon sources credited in the annex.

frontier economics DNV

2. Pathway costs 2040 SynLNG for CH4 end-use

This pathway features the upstream transformation to synthetic natural gas – due to the CH4 end-use, no re-transformation into H2 is required



Source: Frontier Economics

* Transformation losses are counted towards the associated technology.

Key assumptions

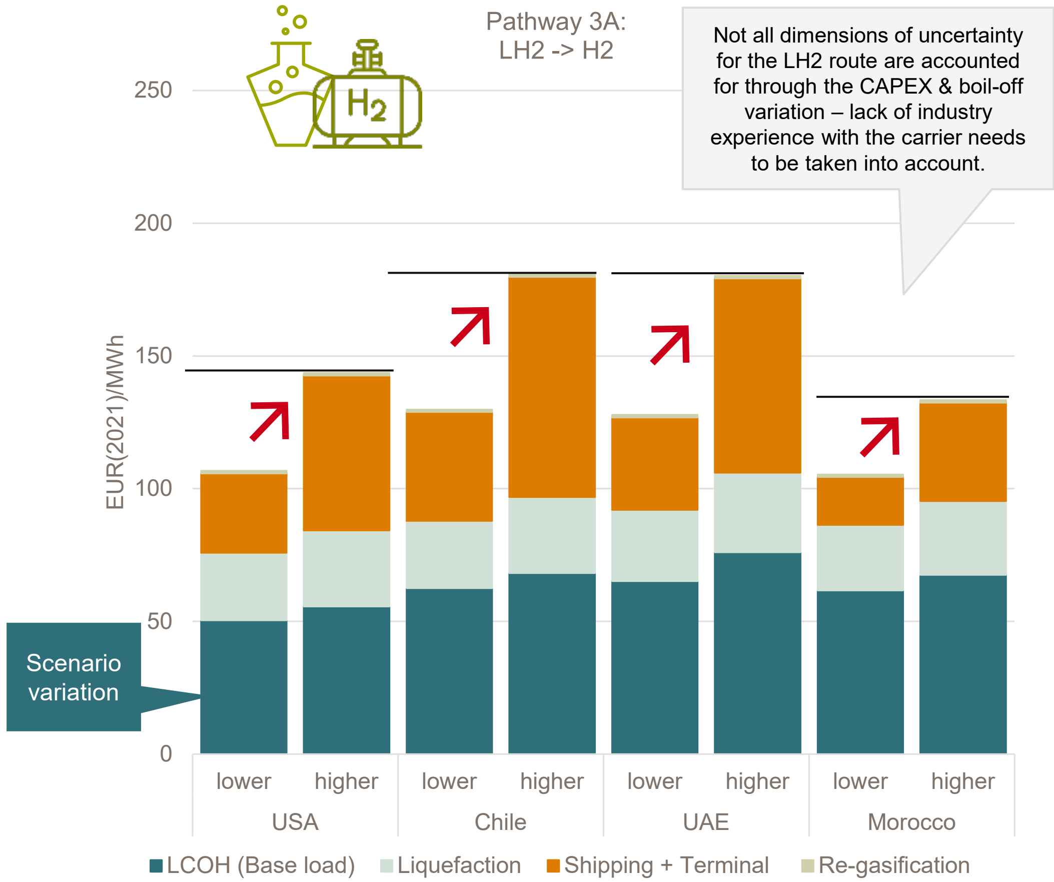
2040 Technology			Other comments	Source
Cathalytic methanation	292	EUR/kW(CH4)	with OPEX **4%**(capex) p.a. & **25 years** depreciation, **75%** efficiency and **0.2** t(CO2)/MWh(CH4)	Moritz et al. (2021)
Upstream methanation	40-209 (Scenario variation)	EUR/t CO2	Lower range biogenic carbon procurement. Upper range high-cost DAC (**756** EUR/(t(C02) p.a.), electricity requirement variation (incl. heat demand, **1.5 – 2.3** MWh(el)/t(CO2). Based on local LCOE in sourcing country.	Moritz et al. (2021), Brown + Hampp (2023), Cormos et al. (2022), IEA (2023b)
NG liquefaction	300 – 717	EUR/kW(LNG) (Scenario variation)	with OPEX **4%**(capex) p.a. & **25 years** depreciation, **95%** efficiency, **0.5** MWh(el)/t(LNG) electricity demand	Agora (2023), DNV, FVV (2021)
Shipping costs (excl. terminal and boil-off losses) – LNG ship	16 – 59	EUR/t(LNG), depending on sourcing country	Cost-based calculation of an LNG ship using transport distance. **16 EUR/t** is the value for Morocco, **59 EUR/t** is the value for Chile. Boil-off gas used as ship fuel.	Agora (2023)
Boil-off losses	0.16%	Per day	Considered for the transport route + 5 days at import/export-terminal each.	Agora (2023)
Import + export-terminal & port costs	16.6	EUR/t(LNG)	(Un-)loading costs + costs for laytime.	Own assumption, based on tariff review
LNG re-gasification	64-192	EUR/kW(CH4) (Scenario variation)	with OPEX **4%**(capex) p.a. & **25 years** depreciation, **98.5%** efficiency	Agarwal (2020)

All EUR-figures are in real EUR-2021 terms.

Icon sources credited in the annex.

2. **Pathway costs 2040** LH2 as an H2 carrier

The LH2 pathway can come at relatively low prices in the future – however, the lack of experience with the carrier must be considered



Source: Frontier Economics

* Transformation losses are counted towards the associated technology.

Key assumptions

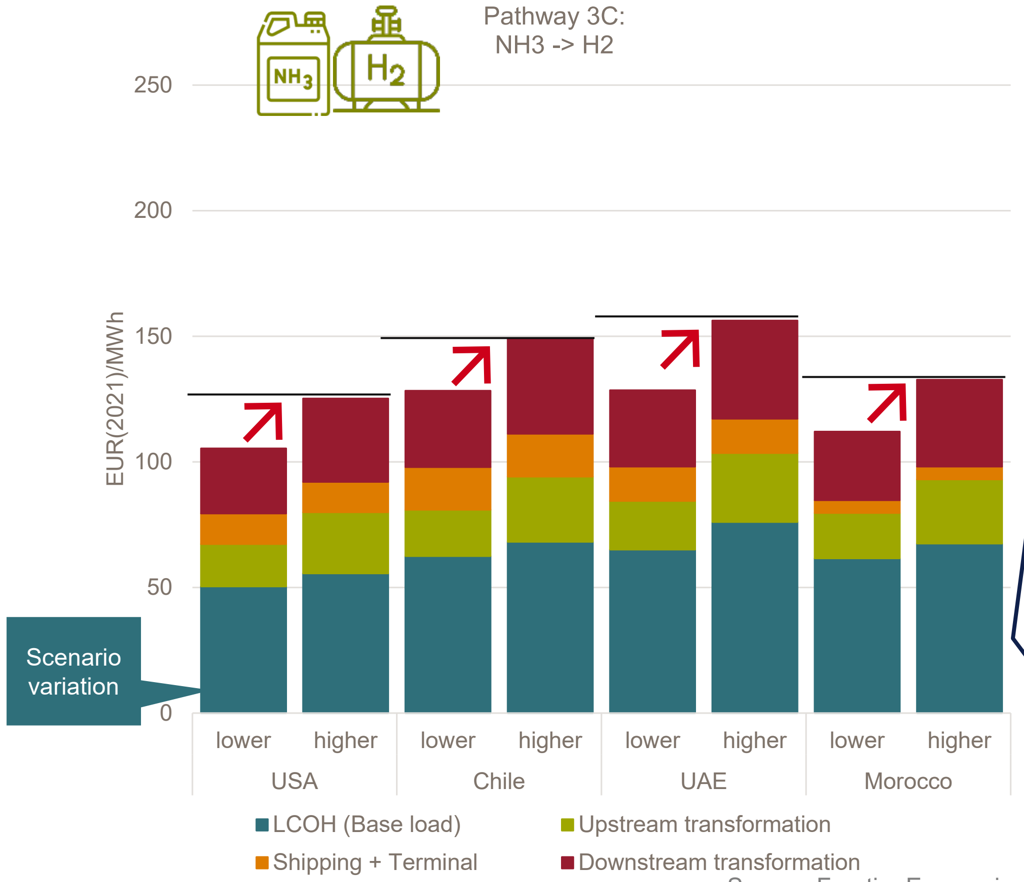
2040 Technology		Scenario variation	Other comments	Source
H2 liquefaction	3,680 – 4,523	EUR/t H2 p.a.	with OPEX **4%**(capex) p.a. & **30 years** depreciation, **98%** efficiency and **7.4** kWh(el) per kg(H2)	Agora (2023), IEA (2019)
Shipping costs (excl. terminal + boil-off losses) – LH2 ship	197 – 733	EUR/t H2	Cost-based calculation of an LH2 ship using transport distance. **197 EUR/t** is the value for Morocco, **733 EUR/t** is the value for Chile. Boil-off gas used as ship fuel.	Agora (2023)
Boil-off losses	0.5%-2%	per day	Considered for the transport route route + 5 days at import/export-terminal each. Upper range assumes lower learning curve from today's technology than anticipated.	Agora (2023)
Import + export-terminal & port costs	197	EUR/t H2	(Un-)loading costs + costs for laytime.	IEA (2023b), Baehr et al (2023), Derking et al. (2019)
Re-transformation	11	EUR/t H2 p.a.	with OPEX **3%**(capex) p.a. & **10 years** depreciation, and 0.7 kWh(el) per kg(H2)	Agora (2023)

All EUR-figures are in real EUR-2021 terms. 33.3 kWh/kg(H2).

Icon sources credited in the annex.

2. Pathway costs 2040 Ammonia as an H2 carrier

The ammonia pathway is the most prominent one in today's public discourse – significant cost-savings are enabled through the direct end-use of ammonia



Source: Frontier Economics

* Transformation losses are counted towards the associated technology.

Key assumptions

2040 Technology	CAPEX		Other comments	Source
Haber Bosch	310-650	EUR/t(NH3) p.a.	with OPEX **2%**(capex) p.a. & **30 years** depreciation, **88%** efficiency	IRENA (2022), IEA(2023)
Shipping costs (excl. terminal and boil-off losses) – Ammonia ship	20 – 81	EUR/t(NH3)	Cost-based calculation of an ammonia ship using transport distance. **20 EUR/t** is the value for Morocco, **54 EUR/t** is the value for Chile. Fuel demand of 700 kWh/km, with 0.11 EUR/kWh (renewable) ship fuel cost.	Agora (2023)
Import + export-terminal & port costs	6.6	EUR/t(NH3)	(Un-)loading costs + costs for laytime.	Baehr et al. (2023)
NH3 Cracking	400-720	EUR/kW(H2)	with OPEX **3%**(capex) p.a. & **30 years** depreciation, **81%** efficiency (incl. heat consumption)	IRENA (2022), Fraunhofer ISI (2022) upper range

Scenario variation

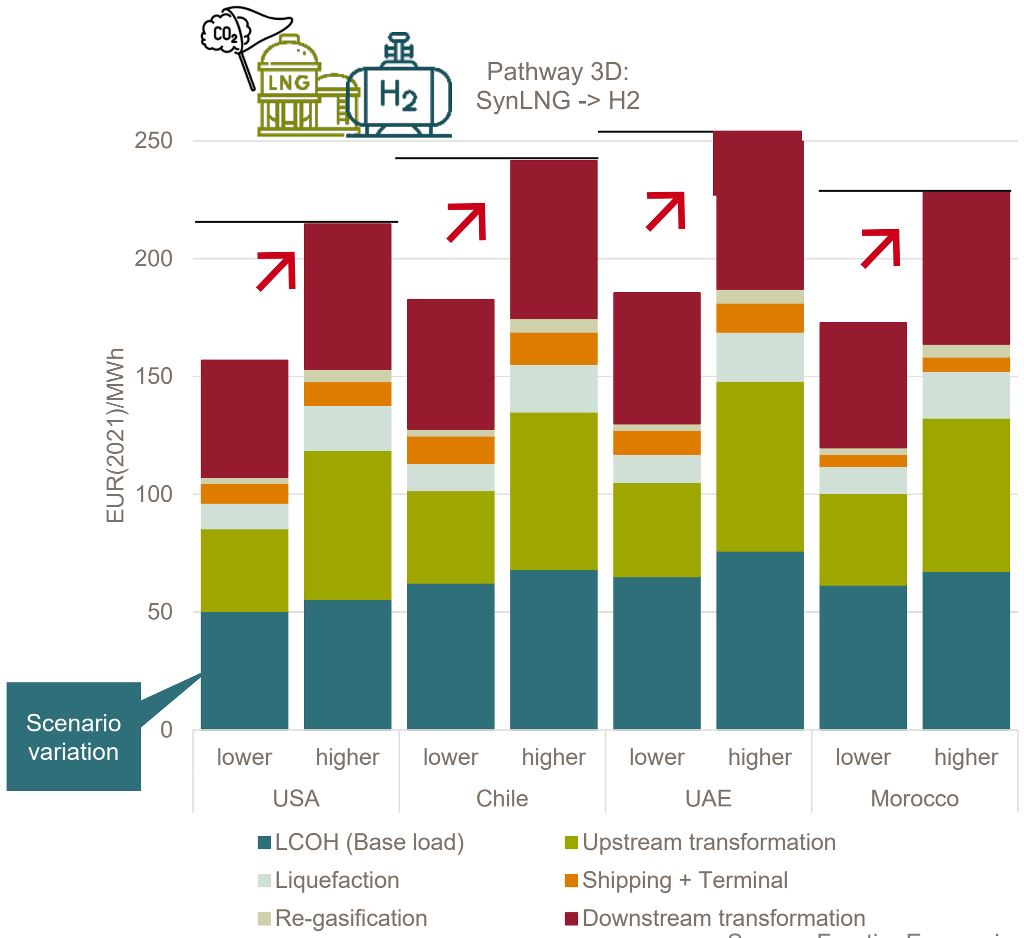
Scenario variation

All EUR-figures are in real EUR-2021 terms.

If Ammonia is **considered for direct use** (e.g. in industry), the re-transformation costs would not be required.

2. **Pathway costs 2040** SynLNG for H2 end-use

Re-transforming synthetic LNG into hydrogen comes at high re-transformation costs, rendering this pathway to be the most expensive one considered



Source: Frontier Economics

* Transformation losses are counted towards the associated technology.

Key assumptions

2040 Technology			Other comments	Source
Cathalytic methanation	292	EUR/kW(CH4)	with OPEX **4%**(capex) p.a. & **25 years** depreciation, **75%** efficiency and **0.2** t(CO2)/MWh(CH4)	Moritz et al. (2021)
Upstream methanation	40-209	EUR/t CO2	Lower range biogenic carbon procurement. Upper range high-cost DAC (**756** EUR/(t(C02) p.a.), electricity requirement variation (incl. heat demand, **1.5 – 2.3** MWh(el)/t(CO2). Based on local LCOE in sourcing country.	Moritz et al. (2021), Brown + Hampp (2023), Cormos et al. (2022), IEA (2023b)
NG liquefaction	300 – 717	EUR/kW(LNG)	with OPEX **4%**(capex) p.a. & **25 years** depreciation, **95%** efficiency, **0.5** MWh(el)/t(LNG) electricity demand	Agora (2023), DNV, FVV (2022)
Shipping costs (excl. terminal and boil-off losses) – LNG ship	16 – 59	EUR/t(LNG), depending on sourcing country	Cost-based calculation of an LNG ship using transport distance. **16 EUR/t** is the value for Morocco, **59 EUR/t** is the value for Chile. Boil-off gas is used as ship fuel.	Agora (2023)
Boil-off losses	0.16%	per day	Considered for the transport route + 5 days at import/export-terminal each.	Agora (2023)
Import + export-terminal & port costs	16.6	EUR/t(LNG)	(Un-)loading costs + costs for laytime.	Own assumption, based on tariff review
LNG re-gasification	64-192	EUR/kW(CH4)	with OPEX **4%**(capex) p.a. & **25 years** depreciation, **98.5%** efficiency	Agarwal (2020)
ATR	920	EUR/kW(H2)	with OPEX **3%**(capex) p.a. & **20 years** depreciation, **80%** efficiency, **0.14** kWh(el)/kWh(H2) electricity requirement	Agora (2023)

Scenario variation

Scenario variation

All EUR-figures are in real EUR-2021 terms.

Icon sources credited in the annex.

Sources

Parameter assumptions referenced

- Agora (2023)
- Baehr et al. (2023)
- Braendle et al. (2021)
- Brown and Hampp (2023)
- CATF (2023)
- Cormos et al. (2022)
- Damodaran (2023)
- Derking et al. (2019)
- ENTEC (2023)
- Fraunhofer ISI (2022)
- FVV (2021)
- IEA (2023a), IEA (2023b), IEA (2023c), IEA (2022), IEA (2019)
- IRENA (2022)
- Moritz et al. (2021)
- Agarwal (2020)

Additional sources for icons used

- Flaticon (1, 2, 3, 4, 5, 6)

A.2: Appendix 2

Glossary

Appendix 2.1

Glossary

Acronym	Meaning
ATR	Autothermal Reforming
BCM	Billion Cubic Meter
BOG	Boil-off Gas
CAPEX	Capital Expenditure
CCUS	Carbon Capture Utilisation and storage
CHP	Clean Hydrogen Partnership
convLNG	Conventional Liquid Natural Gas
DAC	Direct Airc Capture
EHB	European Hydrogen Backbone
ETO	Energy Transition Outlook
EU	European Union
EUR	Euro
FSRU	Floating Storage and Regasification Unit
FSU	Floating Storage Unit
GBS	Gravity Based Structure
GJ	Gigajoule
HP	High Pressure
kg	Kilogram
km	Kilometer
kW	Kilowatt

LCOE	Levelized Cost of Electricity
LCOH	Levelized Cost of Hydrogen
LH2	Liquid Hydrogen
LNG	Liquid Natural Gas
LOHC	Liquid Organic Hydrogen Carrier
LP	Low Pressure
mJ	Milijoule
MS	Member States
Mt	Mega Tonne
MW	Megawatt
MWh	Megawatt-hour
NG	Natural Gas
NL	Netherlands
NRA	National Regulatory Authority
nTPA	Negotiated Third Party Access
OPEX	Operating Expenditure
PCI	Project Common Interest
PtX	Power-to-X
RES	Renewable Energy Resources

Appendix 2.2

Glossary

Acronym	Meaning
RFNBO	Renewable Fuel of Non-Biological Origin
rTPA	Regulated Third Party Access
SMR	Steam Methane Reforming
STEPS	Stated Policies Scenario
synLNG	Synthetic Kiquid Natural Gas
T	Tonne
TJ	Terajoule
TRL	Technology Readiness Level
TWh	Terawatt-hour
TYNDP	Ten-Year Network Development Plan
UAE	United Arab Emirates
USA	United States of America
WACC	Weighted Average Cost of Capital
Yr	Year

Thank you.

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