GIIGNL New Gas Supply Chains Study Phase 2

March 2026

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Phase 2 of the GIIGNL New Gases Study

BACKGROUND AND OBJECTIVES

Deepening the analysis of new gas supply chain economics, expanding regional coverage, and providing a critical assessment of regulatory frameworks

Background from Phase 1

In 2024, GIIGNL Central Office launched a study on New Gases (Phase 1), aiming to:

- Analyze and compare the efficiency, emissions, and cost of various new gases.
- Provide an Excel tool that allows users to test different key parameters, such as CAPEX, load factors, etc.
- Compare the economics and emissions between regions and identify potential trade flows between
  - **Supply areas:** Australia, US Gulf Coast, Middle East, and North Africa
  - **Demand areas:** Japan and Europe

This study has been presented to the Commercial Study Group of GIIGNL, which has expressed interest in a follow-up work

Phase 2 Objectives

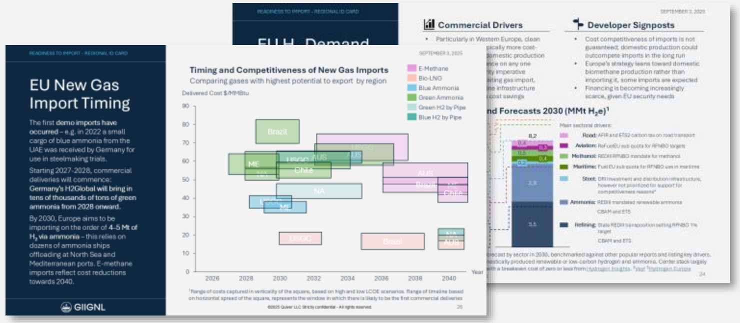
The purpose of this study (Phase 2) is to provide GIIGNL members with an updated and comprehensive analysis of the development of new gases (e.g., low-carbon hydrogen (H_2), ammonia (NH_3), synthetic methane, and bio-LNG) in the context of evolving regulatory frameworks, market dynamics, and geographical developments

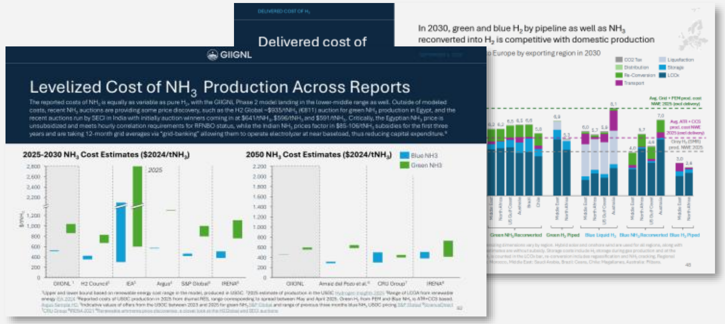
This follow-up work aims to address key knowledge gaps identified by the Commercial Study Group (CSG) and incorporate their requested extensions, which include:

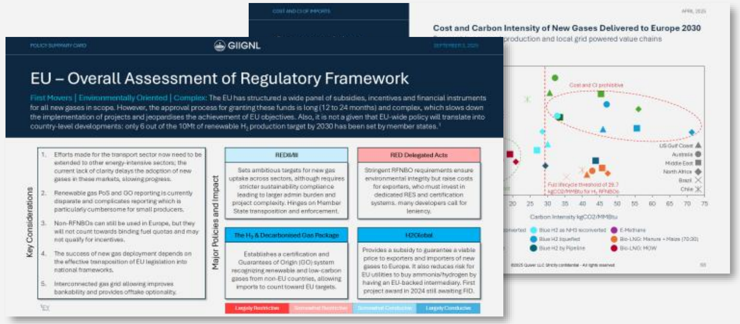
- **Expansion of export regions**, including Brazil and Chile
- **Benchmarking of model results** to other well-known sources
- **Assessment of the current regulatory frameworks'** impact on new gas supply chain development

Phase 2 Deliverable Table of Contents

Divided into 3 work packages – click on the section or sub-section to jump to that part of the deliverable







New Gas policy and projects have seen appreciable growth, but momentum continues to slow down

New gases projects are moving forward around the world, particularly in areas where clear policy drivers and optimal commercial factors are in play. However, further project cancelations, geopolitics, and policy uncertainty in Q1 2026 is reducing the spectrum of quality opportunities. Internationals new gas value chains are struggling to emerge as demand projections fall short

Good News

>$110B
In global committed (FID+) investment for clean H_2 projects until 2030

>500
Clean H_2 and derivatives projects beyond FID worldwide

+$35B
Increase in committed investment for H_2 and derivative projects globally in 2025 from 2024

>4 Mtpa
Of committed clean H_2 and derivative offtake by 2030 (FID+)

Bad News

-500%
FID was down by 5x in 2025 vs 2024 for H_2 and derivatives projects

~55
Clean H_2 and derivatives projects have been publicly canceled in the past 18 months (~3% of the pipeline)

8
Major EU MS's have not fully transposed REDIII industry quotas incl. Germany, Spain, France[1]

97%
of FID+ projects have either production or offtake located in regions with explicit H_2 policies

"Good News" from interviews and surveys conducted with over 70 leaders from a subset of H2 Council members, released Sept 2025: H2 Council 2025

Contents and Main Findings of Phase 2

In Phase 2, many updates were made to the model to improve its functionality and regional specificity to obtain certain insights. A benchmark of costs was performed, resulting in an update of new gas costs presented in WP2. Additionally, a critical analysis of each study regions readiness to export, and regulatory framework was performed and presented in WP1 and WP3 respectively

WP1 - Regional Analysis of Readiness to Export

1. The Middle East and US (and China) are in a **class of their own as exporting regions**, due to the outsized availability of capital, export projects beyond FID, infrastructure, and policy. **However wavering international demand is slowing progress**
2. Commercial blue and green NH_3 exports are expected **between 2028-2030** (with the exception of China already operational)
3. **2026 is a critical year for project FIDs** in Australia, Brazil, Chile, the US, and Middle East, most of which are driven by demand side incentives (e.g. H2Global and Japan CfD auctions)

WP2 - Results Benchmark and Comparative Analysis

1. Blue and green NH_3 / H_2 imports are **expected to become competitive with conventional domestic H_2 production in Europe by 2030 and 2040 respectively**, assuming a **carbon tax of ~$108tCO_2$ and $152tCO_2$**. The gap is not expected to close for imports into Japan until 2050 due to a lower carbon price outlook
2. Hydrid-RES is required to make economics work for large scale new gas production, **however, less uniform generation profiles lead to higher LCOx**, due to higher storage and oversizing needs (**Brazil Ceara region - 200% above average H_2 storage costs**)

WP3 - Regulatory Analysis and Market Framework Assessment

1. **Regulatory uncertainty is high especially in the EU and US.** Major barriers coming from the **EU Delegated Acts, REDIII industry quotas, and US Three Pillars** environmental stringency. Green NH_3 delivered costs could be **almost twice as expensive** when complying with these rules
2. Since July 2024, **new billion-dollar incentives for new gases have been rolled out** (or are in process) in Australia, Japan, Chile, Europe, Brazil, Saudi Arabia and Oman, **while incentives (45V, H2 Hubs) are being pulled back in the US**

Regional Export Potential

The Middle East and US Gulf Coast are poised to be **first movers** on Green Ammonia and Blue Ammonia export respectively

Chile, Australia, the Middle East (except UAE), and North Africa have **predominantly export-focused strategies**, leaving project development reliant on offtake contracts with Europe and East Asia which has fallen short and pushed back development timelines. Most regions are shifting their focus to **domestic demand** to provide an anchor for exports, which adds stability in light of increasingly dynamic geopolitics

Regional Export Potential, Strengths, and Weaknesses[1]

Exporter	Score	Strengths	Weaknesses
Middle East	8.7	Direct investment, **low regulatory complexity**, business conducive	**Regional instability poses threat to shipping lanes**
US Gulf Coast	8.1	**Largest availability of incentives** even with IRA scope reductions	**Political uncertainty**. Difficulty meeting Three Pillars and wage/ content adders for full 45V incentive
Australia	6.3	**Ramping government support**, world class diurnal solar and wind resource, land availability	High natural gas costs, **funding pulls, and pipeline attrition**
Chile	5.1	Highest solar and wind capacity factors and **most competitive LCOx**, political stability	High capital costs, **significant infrastructure development required** in remote regions (1/3 of projects)
Brazil	4.9	**Lowest carbon intensity grid in scope**, attracting European investors looking to simplify RFNBO qualification. Plentiful biomass	**Bureaucratic delays, permitting challenges, and occasionally local opposition**. Fiscal situation could limit public co-investment or tax breaks; high capital costs
North Africa	4.2	**Proximity to Europe reducing midstream costs**, world class renewable resources, existing LNG export and pipelines	Nascent regulatory frameworks and investor clarity, land leases, and profit repatriation. **Water scarcity, major infra upgrades**

[1]The ranking includes cost data taken from the specific regions selected in each country

Top Near-Term New Gas Value Chains

Ammonia value chains are expected to establish the first major flows between regions, with favourable pricing, acceptable carbon intensity (CI) in both Europe and Japan, and a handful of projects beyond FID

Gas	Exporter	Importer	Timeline	Cost ($/MMBtu)[1]	CI ($kgCO_2$/MMBtu)[2]	Development
Green Ammonia	Middle East	Europe	2027-2028	54-62	9	**NEOM project at 90% construction** as of 2026, with preliminary agreements signed with European offtakers expected 2027; **Oman has numerous large projects expecting FID in 2026-2027**
Blue Ammonia	USGC	Japan	2029-2030	40-42	28	Ample CCS infra and incentives (IRA 45Q) drive a **pipeline of 11 blue ammonia projects planned**. Blue Point Ammonia JV (CF, JERA, Mitsui) **have reached FID targeting export to Japan by 2029,** obtained **$6.8B** commitment from Japan CfD program
Green Ammonia	North Africa	Europe	2028-2030	50-56	5	H2Global import tender award to Fertiglobe for green NH_3 from Egypt to Europe, **flows originally expected 2027 but FID delayed**
Blue Ammonia	Middle East	Japan	2029-2030	35-36	22	UAE's ADNOC and Saudi firms pilot cargoes to Japan (2021–2022) and to South Korea and China (2023). **ADNOC-led TA'ZIZ project in the UAE reached FID in 2022**, Mitsui & Co as offtaker
Blue Ammonia	Australia	Japan	2029-2031	58-59	24	Pilot exports of blue NH_3 shipped to Japanese utilities in 2022. **Four main blue hydrogen/ammonia export projects** in advanced pre-FEED or FEED stages
Green Ammonia	Brazil	Europe	2030-2032	57-64	7	Pecem (Ceara state) projects aim for operation by 2030, and multiple other ports (Açu, Suape) could be shipping to Europe and Asia by 2030 if MoUs become contracts (interest signaled by Japan's METI). **EU support is strong, aligning with RFNBO standards**

[1]Lower and upper bound of the estimated delivered cost in 2030 produced with hybrid solar and onshore wind, range corresponding to low and high bound LCOE
[2]Production powered purely by renewables and value chain using local average annual grid intensity projections for 2030 (whole lifecycle considered)

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EU H_2 Demand

Primary Opportunities:

Europe is leading the development of global standard-setting and sustainability criteria backing their climate goals. Initial new gas uptake in the EU is supported by **REDIII RFNBO quotas primarily in the transport sector** which could be backed by **penalties of €6-10/kg H_2**. ETS & CBAM puts a price of **~$100-150/t$CO_2$** on domestically produced and imported H_2 an NH_3, especially non RFNBO

Primary Hurdles:

It appears **unlikely that industry quotas will be enforced in many major member states**, creating large uncertainty. Massive infrastructure and new technology needs, such as ammonia cracking. **Regulatory harmonization is complex and slow**

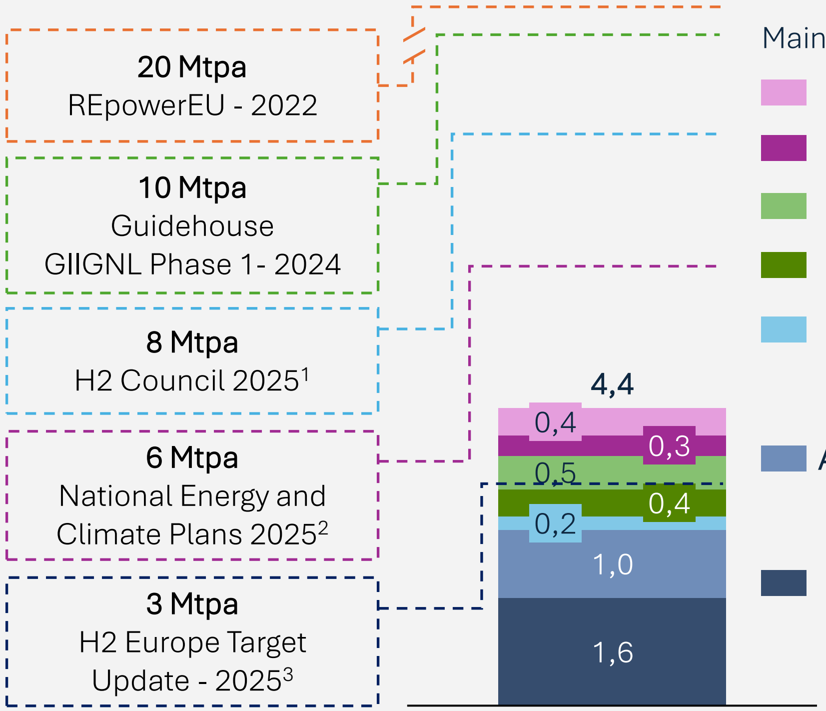
Commercial Drivers

- Particularly in Western Europe, clean gas imports are typically more **cost-competitive than domestic production**
- Avoiding over-reliance on any one supplier is a **security imperative**
- **Repurposing** of existing gas import, storage, and pipeline infrastructure networks **provides cost savings**

Developer Signposts

- **Cost competitiveness of imports is not guaranteed**; domestic production could outcompete imports in the long run
- Europe's strategy leans toward domestic biomethane production rather than importing it; some imports are expected

Clean H_2 Demand Forecasts 2030 (Mtpa H_2e)[1]



Main sectoral drivers:

- **Road:** AFIR and ETS2 carbon tax on road transport
- **Aviation:** ReFuelEU sub quota for RFNBO targets
- **Methanol:** REDIII RFNBO mandate for methanol
- **Maritime:** Fuel EU sub quota for RFNBO use in maritime
- **Steel:** DRI Investment and distribution infrastructure, however not prioritized for support for competitiveness reasons[4]
- **Ammonia:** REDIII mandated renewable ammonia; CBAM and ETS
- **Refining:** State REDIII transposition setting RFNBO 1% target; CBAM and ETS

[1]Clean hydrogen demand forecast by sector in 2030, benchmarked against other popular reports and listing key drivers. Includes imported and domestically produced renewable or low-carbon hydrogen and ammonia. Center stack largely representative of policy-covered demand with a breakeven cost of zero or less, revised down in Feb 2026 due to recent developments Hydrogen Insights. [2]Veyt [3]Hydrogen Europe [4]Commission's Action Plan

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Japan H_2 Demand

Primary Opportunities:

Japan aims to leverage **existing infrastructure** as much as possible, promoting NH_3 coal co-firing and e-methane injection in existing gas pipelines and boilers. Like Europe, they are seeking a **first-movers' advantage by locking in low long term supply contracts with preferential pricing**. METI has allocated ~$51 billion for H_2 infrastructure, with ~$19 billion going to CfDs for H_2 and ammonia imports underway[2]

Primary Hurdles:

Nascent international CO_2 accounting framework and compliance markets. Safety concerns around NH_3 imports and combustion near urban centers

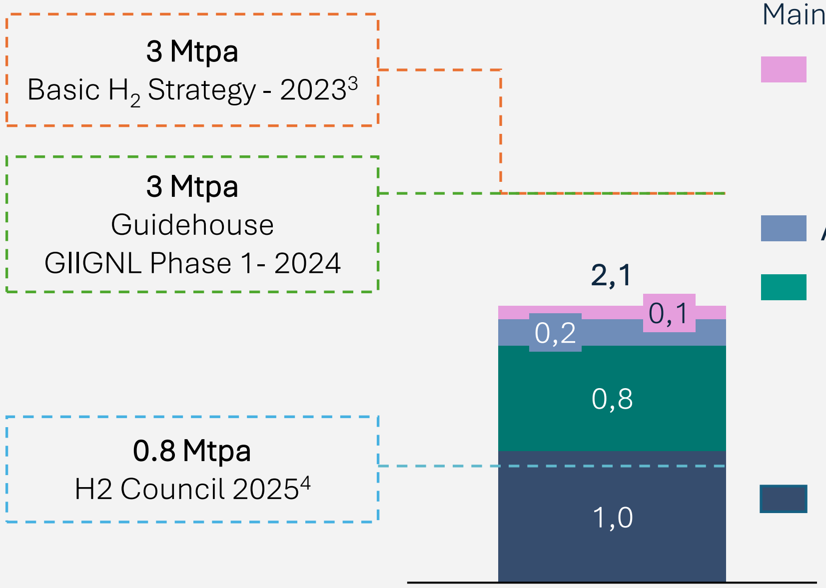
Commercial Drivers

- High-cost domestic production and land constraints make imports necessary to do cost-effective decarbonization
- **Technology innovation hub** leading H_2 turbines, FCEVs, NH_3 co-firing, H_2 carrier, and ship development, etc.
- **Extensive LNG import infrastructure** enable bio-LNG and e-methane blends

Developer Signposts

- Japanese buyers prefer long-term offtake agreements with politically stable countries and often seek **JV or equity involvement to secure supply chain stability**
- **Biogenic CO_2 for e-methane production not yet an imperative as in the EU** as current regulations see once recycled fuels as carbon neutral

Clean H_2 Demand Forecasts 2030 (Mtpa H_2e)[1]



Main sectoral drivers:

Transport: Road: station and vehicle goals (impact is minor)
Maritime: emissions caps and MEPC 80
Aviation: airlines beginning to trial SAF

Ammonia: Depends on cost competitiveness of imports

Power: Main driver of new demand
USD 19 billion CfD support over 15 years
Aiming for 1% of electricity gen. by H_2/NH_3 by 2030
Power capacity auctions – NH_3 co-fired power

Refining: Decarbonizing existing demand
Domestic and international blue H_2 and NH_3

[1]Clean hydrogen demand forecast by sector in 2030, benchmarked against other popular reports and listing key drivers. Includes imported and domestically produced renewable or low-carbon hydrogen and ammonia. Adding a potential estimate of transport demand from road, maritime, and aviation that could materialize if compliance ramps up. [2]The view from Japan [3]Japan: hydrogen strategy [4]breakeven cost of zero or less from Hydrogen Insights

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Delivered cost of H_2 to Europe 2030

By 2030, the **cheapest H_2 imports are expected to come from North Africa and the Chile**, driven mainly by low-cost solar and wind resources for Chile, and proximity to Europe for North Africa, saving midstream costs

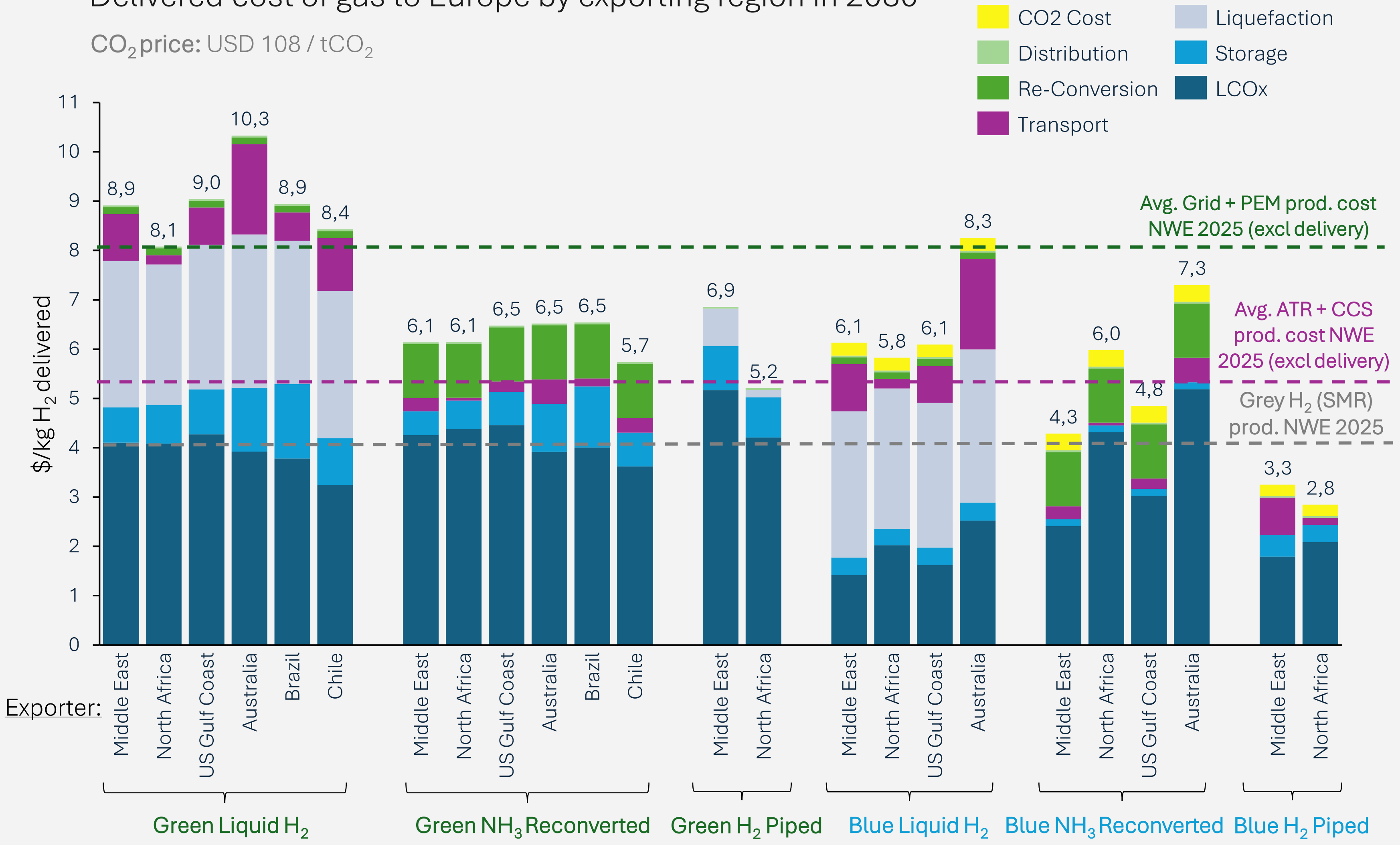
Liquified green H_2 imports are not likely to be competitive with domestic production by 2030. **NH_3 reconverted should be cheaper than domestic green H_2, but not domestic blue or grey H_2 production.** Blue H_2 imports by pipe would be by far the most competitive due to relatively low gas prices abroad, yet no projects are planned

Non-RFNBO value chains are subject to CBAM pricing, adding ~$0.30-0.50/kgH$_2$ to imported costs and reflecting Europe's bias for RFNBOs, which could have the same carbon intensity (<70% lifecycle GHG reductions) but can use an electricity emissions factor of zero under CBAM

In 2030, green and blue H_2 by pipeline as well as NH_3 reconverted into H_2 is competitive with domestic production

Delivered cost of gas to Europe by exporting region in 2030

CO_2 price: USD 108 / tCO_2



Optimal hybrid solar and onshore wind are used for all regions, regional specific capacity factors available in associated model. A flat discount rate of 7% is assumed. All cost estimates are without subsidy. Storage costs include H_2 storage during gas production and at the export terminal. Conversion of H_2 to NH_3 is counted in the LCOx bar, re-conversion includes regassification and NH_3 cracking. It is assumed RES based value chains ("green H_2/NH_3") are RFNBO compliant and thus are not subject to CBAM. However, the non RFNBO value chains are subject to CBAM pricing, in this case having zero electricity emissions for production and the value chain, but accounting for the cost of methane emissions and CCS alone under the assumed CO_2 price.

Delivered cost of H_2 to Japan 2030

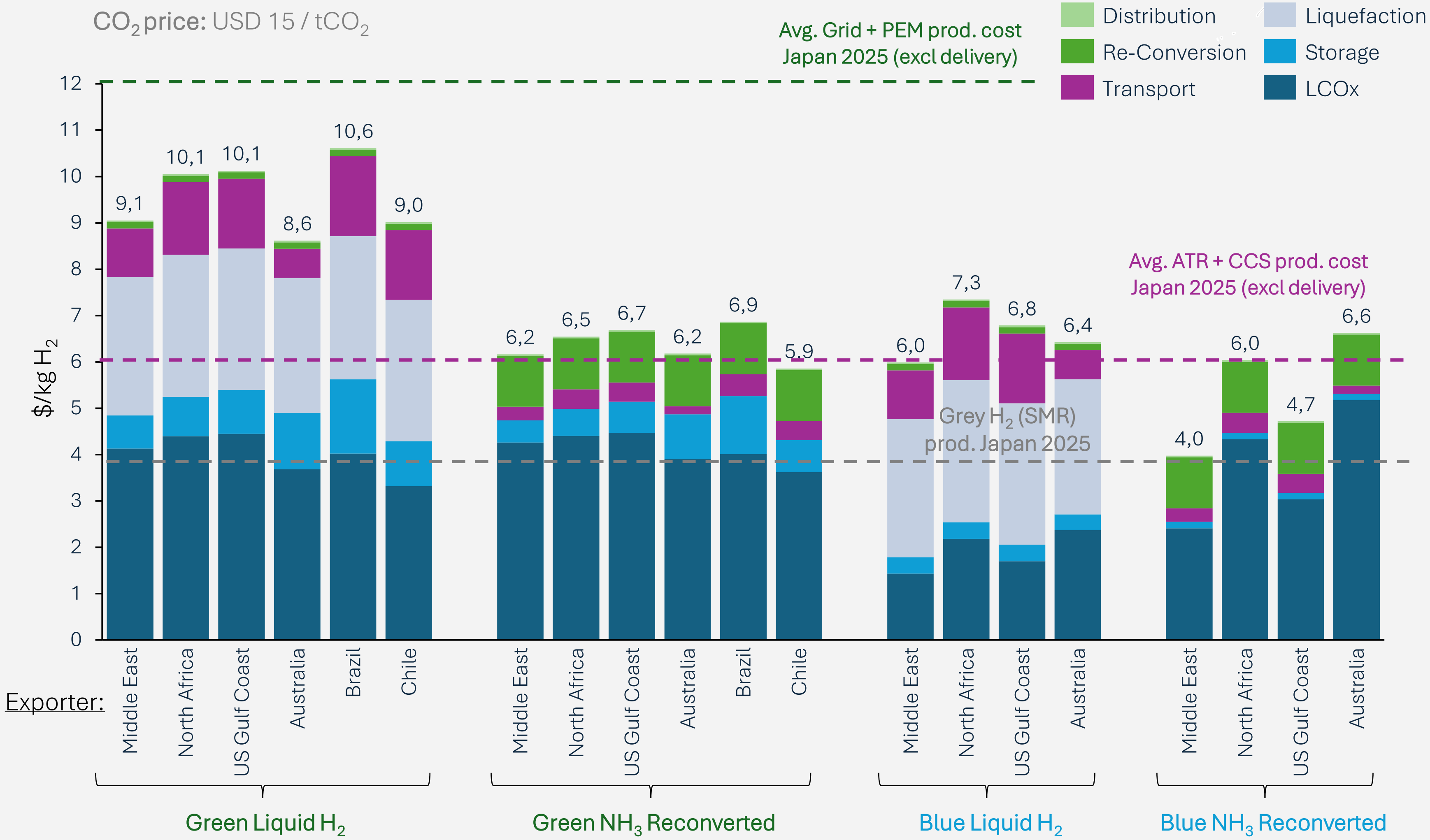
For Japan, Australia, Chile, and the Middle East are the most competitive suppliers of most H_2 molecules

Green and blue NH_3 reconverted into H_2 costs less than green H_2 produced in Japan, **which could catalyze investment into key technological bottlenecks along the supply chain such as NH_3 cracking, and the demand side such as NH_3 co-fired power, green steel production, transport and more.** Despite competitiveness of imports, uptake will come down to willingness to pay and government support

A CBAM equivalent does not currently exist in Japan, so no CO_2 pricing is considered for new gas imports. **This creates and advantage for Japanese buyers**

Similar to Europe, a price premium persists for imported H_2 compared to domestic grey or blue H_2 production

Delivered cost of gas to Japan by exporting region in 2030



Energy prices, capacity factors, and oversizing dimensions vary by region. Hybrid solar and onshore wind are used for all regions, along with a flat discount rate of 7%, and all cost estimates are without subsidy. Storage costs include H_2 storage during gas production and at the export terminal. Conversion of H_2 to NH_3 is counted in the LCOx bar, re-conversion includes regassification and NH_3 cracking. Regional capacity factor specificity: North Africa: Morocco, Middle East: Saudi Arabia, Brazil: Ceara, Chile: Magallanes, Australia: Pilbara

[1] The view from Japan: 2025

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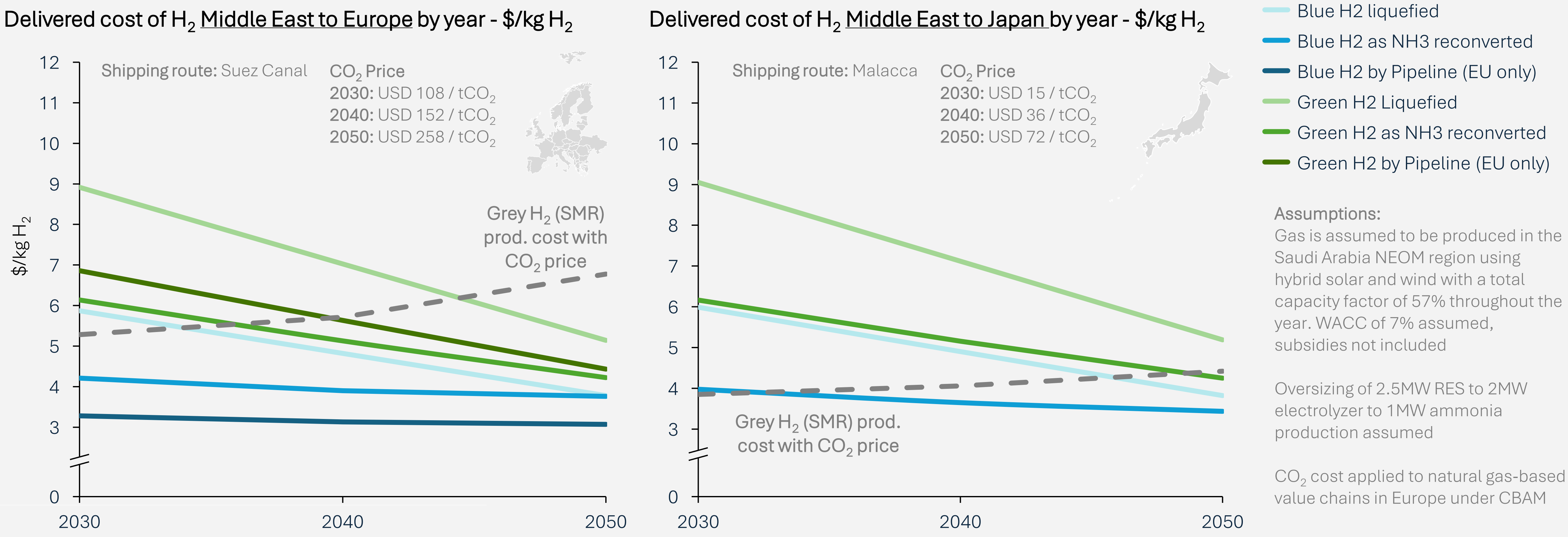
Clean H_2 supply chains are expected to become competitive with local grey H_2 production, and markets will need to adapt to price discovery over time

Large cost reductions are expected for green H_2-based supply chains due to marked improvements in **electrolyzer CAPEX (from ~$1,150/kW in 2030 to ~$750 /kW H_2 in 2050),** efficiency **(from 72% in 2030 to 80% in 2050),** and LCOE reductions **(-35% on average)**. As a result, reductions in OPEX and balancing costs (batteries and on-site H_2 storage) will occur, implying a need to implement flexible H_2 contracting reflecting economies of scale. A high carbon tax penalizes unabated hydrogen production to the extent **that most clean options are more economical in Europe by 2040**, however, the same is not expected to be true in Japan, based on a weaker carbon price outlook, **which could mean support schemes will still be necessary in 2040**, potentially weaning off towards 2050



Assumptions:

Gas is assumed to be produced in the Saudi Arabia NEOM region using hybrid solar and wind with a total capacity factor of 57% throughout the year. WACC of 7% assumed, subsidies not included

Oversizing of 2.5MW RES to 2MW electrolyzer to 1MW ammonia production assumed

CO_2 cost applied to natural gas-based value chains in Europe under CBAM

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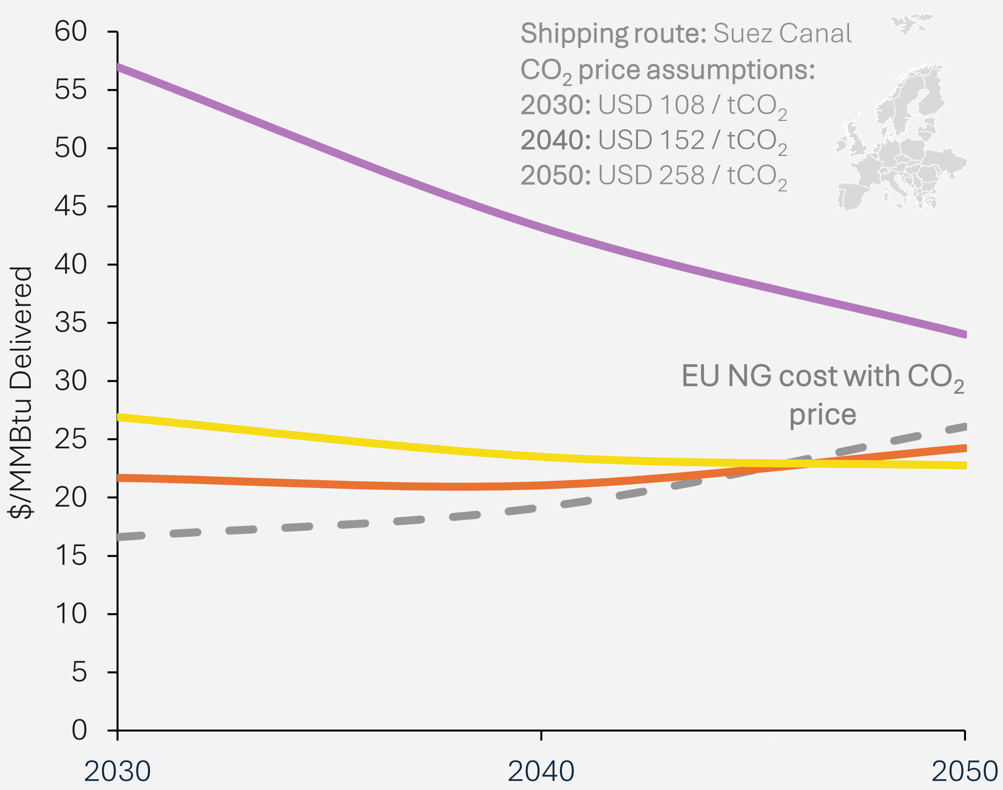
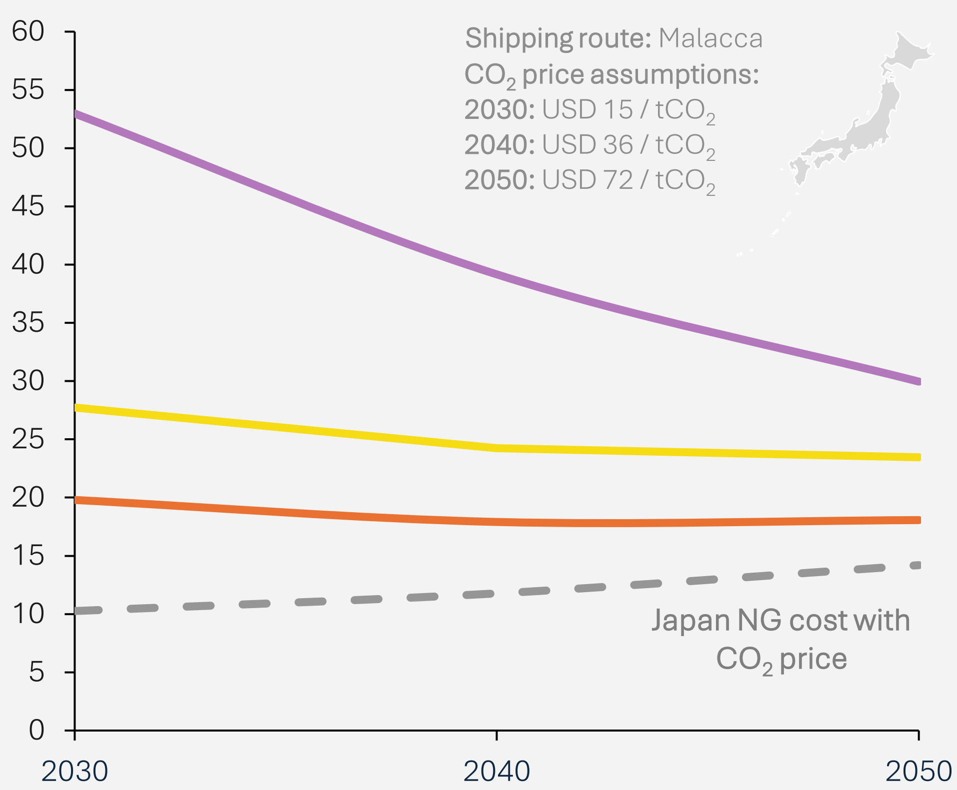
Costs converge towards 2050, opening up markets for decarbonized CH_4, however, economies of scale are needed to drive cost reductions

E-methane and bio-LNG imports into Europe will become increasingly competitive with fossil LNG moving forward as carbon prices increase. **E-methane import costs are expected to decrease by ~40% between 2030 and 2050** due to technological improvements and economies of scale, assuming **electrolysis CAPEX reduces from $1,150/kW in 2030 to $750/kW in 2050**, and **methanation CAPEX from $775/kW in 2030 to $465/kW in 2050**.[1] Japan currently sees a larger role for e-methane in meeting their long-term 90% carbon-neutralized city gas targets for 2050[2], however offtakers in Europe may compete for volumes for e-methane in ETS covered sectors as the cost premium tightens

Delivered cost of CH_4 US Gulf Coast to Europe - $/MMBtu



Delivered cost of CH_4 US Gulf Coast to Japan - $/MMBtu



- E-Methane: Dedicated RES and PPAs
- Bio-LNG: Municipal organic waste
- Bio-LNG: Wet manure + maize (70-30)

Assumptions:

Energy prices, capacity factors, and oversizing dimensions vary by region. Hybrid solar and onshore wind are used for all regions, along with a flat discount rate of 7%, and all cost estimates are without subsidy

Biogenic CO_2 for e-methane exported to Japan sourced at $20/t$CO_2$ from a gas processing plant, while exports to the US are assumed to be using biogenic CO_2 from a pulp and paper plant at $200/t$CO_2$, **leading to a 16% increase in LCOx**

Feedstock cost ranges based on the cost curves of manure, MOW, and maize by region IEA

[1] juser.fz-juelich.de
[2] カーボンニュートラルチャレンジ

Competitive Imports to Europe 2030

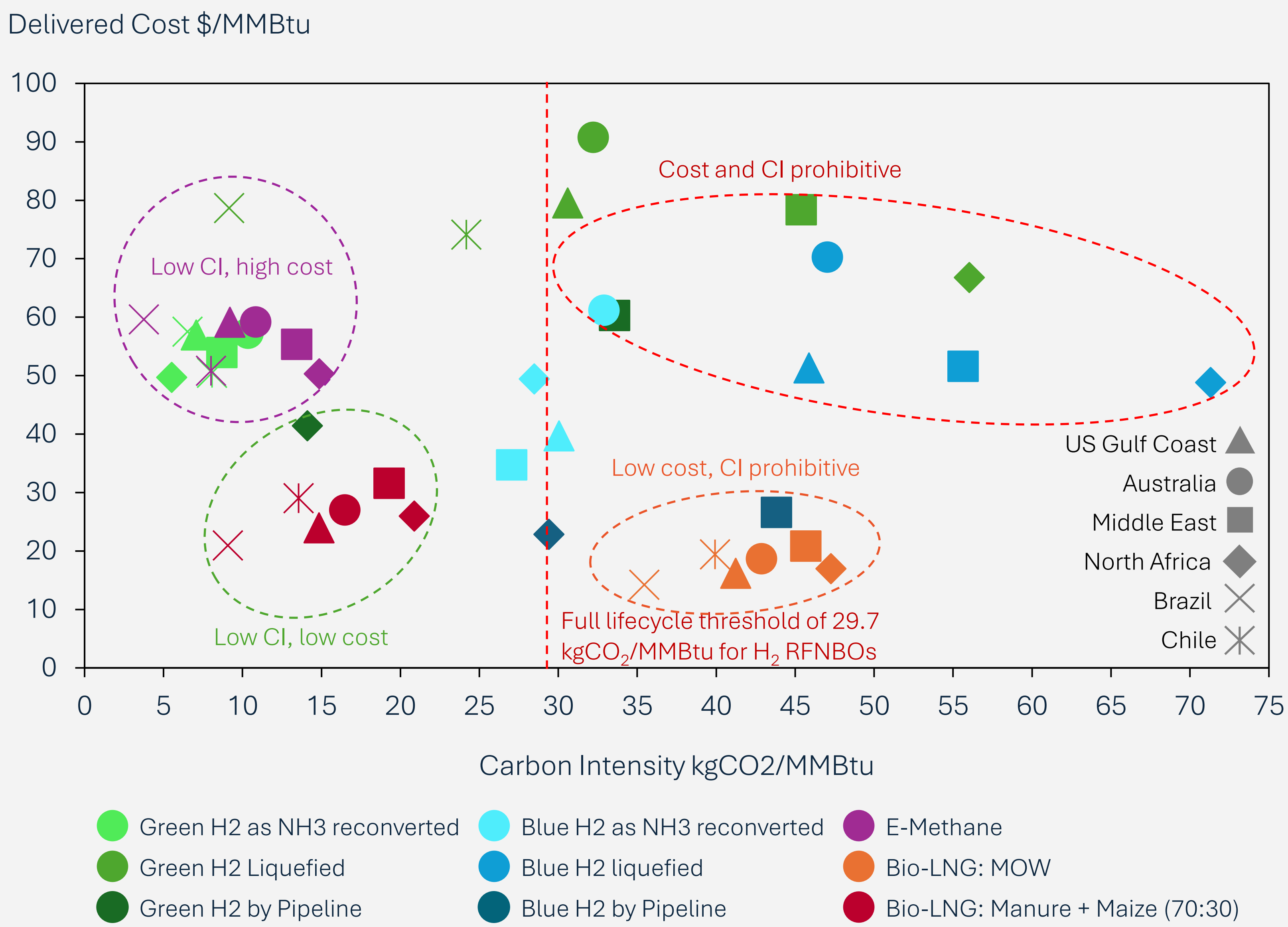
The most competitive and lowest carbon imports theoretically come from bio-LNG from either manure or partial manure feedstocks, **but not many regions are planning to export towards Europe**.

The least carbon intensive value chains, **green NH_3 and e-methane**, are expected to be higher cost in 2030. It is assumed that e-methane is produced using biogenic CO_2 in 2030 from a pulp and paper mill at \$200/tCO_2 as developers future-proof for RFNBO regulations

If gases are not RFNBO certified, they are subject to CBAM pricing on their electricity related emissions

Cost and Carbon Intensity of New Gases Delivered to Europe 2030

Renewable powered production and local grid powered value chains



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Competitive Imports to Japan 2030

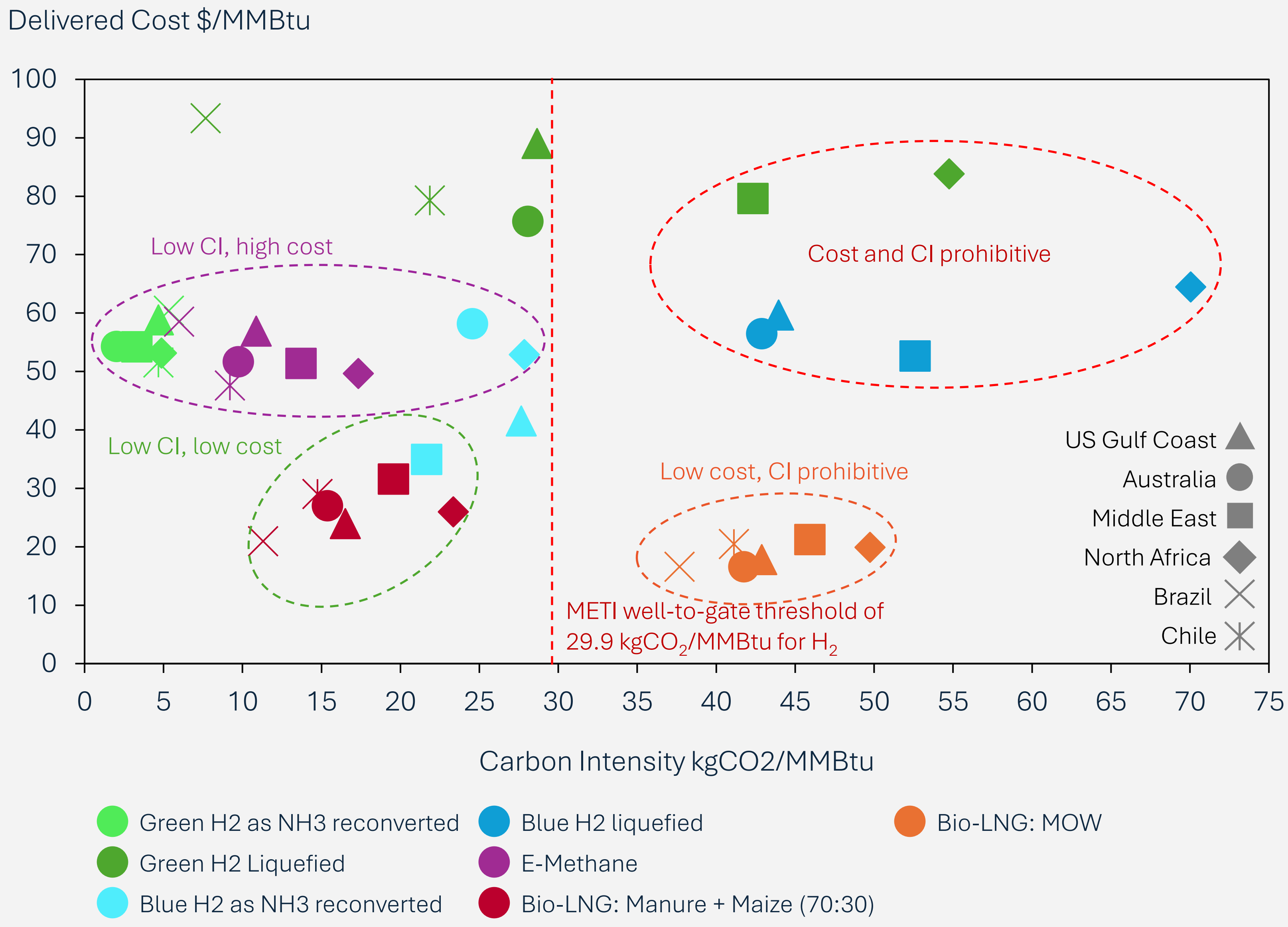
Similar to European imports, the most competitive and lowest carbon imports theoretically **come from manure-based bio-LNG,** however scant volumes are expected to materialize

Blue and green NH_3 reconverted, and e-methane fall withing the carbon intensity thresholds, with **Australia and the Middle East being the most cost competitive suppliers for Japan**

E-methane is assumed to be produced using fossil CO_2 from a gas processing plant at $20/t$CO_2$

Cost and Carbon Intensity of New Gases Delivered to Japan 2030

Renewable powered production and local grid powered value chains



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Comparison of Regional New Gas Policy Frameworks

New gas regulatory frameworks are mostly supportive, with a large gap in terms of incentive budgets

Country	Description	Stability (x/25)[1]	Existence of Policy Barriers	New Gas Incentives[2]
Middle East	Taken as a whole, governments in Saudi Arabia, Oman, and the UAE provide **world leading support** for new gas projects, as it is seen as a strategic priority	24	Demand side pull	>$50 billion
EU	**The EU has structured the widest panel of subsidies, incentives and financial instruments** for all new gases in scope. However, the approval process for granting these funds is long and complex, affecting project development	22	Complexity of Delegated Acts, implementation speed, transposition of industry quotas	>$100 billion[3]
Japan	Tight, targeted subsidy architecture with long-tenor support and capacity payments; **policy is strong, but project uptake/costs will determine buildout**	22	Minimal; lack of certification, many commercial barriers	>$20 billion
Australia	**New Australian government is intent on advancing their new gases export push** by increasing incentives. Political and execution risks are present	19	Additional compliance via Safeguard Mechanism	~$7 billion
Chile	Chile's H_2 strategy enjoys **broad political support**, limited political blockers, long-term vision, and is **prudent with public funds**	17	Environmental concerns	~$3 billion
Brazil	Brazil's clean H_2 policy is in early stages, is a patchwork of policy support. A comprehensive legislative framework (covering guarantees of origin, tax incentives, etc.) **is still under development**	16	Nascent and unproven	~$4.4 billion
US	**Strongest incentive packages for a single country**, although bias and uncertainty have been recently introduced, greatly reducing confidence and reducing funding available for renewable energy-based projects and gases	15	45V reductions, "3 pillars" stringency, Jones Act	>$100 billion in next 10 years, depending on incentive uptake and permanence
North Africa	North African regulatory frameworks **must evolve to ensure projects move from MoU to FID**. Countries rely heavily on Foreign investment	14	Incentives, roadmaps, stability	<$0.5 billion

[1]Detailed scoring found after each policy summary slide [2]WP3
[3]ey-hyvolution-ey-european-hydrogen-20250214.pdf

Many Policy Barriers	Some Policy Barriers	No Real Policy Barriers

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Major Policy Blockers for New Gas Value Chains

Restrictive policies identified involve environmental compliance stringency and a lack of certification/standardization[1]

Delegated Acts on LCFs, RFNBOs, and GHG Accounting: Stringent RFNBO requirements ensure environmental integrity but raise costs for exporters who must invest in dedicated RES or PPAs compliant with stringent rules on additionality, temporal/geographic correlation, especially compared to place like Japan who do not mandate it

Electricity for RFNBOs cannot have been granted financial support. Physical connection is required for PPAs and biogenic CO_2 used for RFNBO. Book & claim would significantly reduce costs

Low-Carbon Fuels (LCFs) are penalized compared to RFNBOs. Even if they meet the same 70% GHG reduction threshold, LCFs must pay ETS/CBAM fees based on emissions from CCS and methane leakage, while electricity for RFNBOs is considered carbon free

Methodology for treating nuclear in grid-sourced H2 production LCA deferred to 2028, potentially delaying such projects

Egyptian Law No. 2/2024 grants big incentives but with conditions that can limit eligibility: 5-year window for signing project agreements; ≥70% foreign-currency financing; ≥20% local components; tight timelines to reach COD

Three Pillars for 45V closely resemble stringent EU Delegated Act rules for green H_2 production. Developers have complained about difficulty and administrative burden of meeting apprenticeship and domestic cost content adders for IRA tax incentives like 45V

The Renewable Fuel Standard has created a strong domestic market for biomethane that is likely to out-compete, and adds compliance for potential bio-LNG exporters

The Jones Act Constraints on domestic marine movements: any coastwise shipment of LNG/alternative fuels (and future NH_3/H_2 bunkering) must use U.S.-built/flag/crewed vessels, a cost and availability hurdle for coastal supply chains

Safeguard Mechanism: Provides an incentive for lowest-CI production facilities, which can trade additional compliance credits. However, hampers gas-based pathways as facilities in scope lose capacity to monetize voluntary credits

Low-Carbon H_2 legal Framework sets a high threshold ($7kgCO_2/kgH_2$) misaligned with importers, and several implementing rules (measurement/LCA scope, chain-of-custody, interoperability) are still to be issued, which slows bankability

Production tax credit (PHBC) is capped and only runs 2028–2032; rules are still being detailed, creating timing gaps for projects trying to FID sooner

Insufficient market mechanisms: Book-and-claim for clean electricity, CH_4 and feedstocks such as biogenic CO_2 would drive cost reductions and development by allowing existing infrastructure to be fully leveraged (GHG Protocol)

[1]List is not exhaustive, see detailed policy assessment for more

Key Signposts for New Gas Value Chains by Geography (1/2)

Europe

- Many are calling for the softening of EU Delegated acts for RFNBOs ahead of the 2028 review and revisions of the ETS system, **which creates uncertainty for export projects** seeking FID in the interim
- **An additional €3bn** is being made available for H_2 projects through the EHB's ongoing third auction which is now considering low-carbon H_2. First auction winners secured subsidy amounts up to **€0.48 per kg**

Japan

- The Green Transformation (GX) Programme (2024) estimated to drive public-private investments of **¥ 150 trillion (~$1 trillion, nearly 3x the annual GDP investment % of the US IRA**) over 10 years for transition to a net-zero economy by 2050. Public finance spine of **¥20 trillion GX Economic/Climate Transition Bonds**, **emissions trading system** (starting FY2026), carbon surcharges on fossil fuel importers (FY2028) and emissions allowance auctions by power generators (FY2033)

US Gulf Coast

- Uncertainty around US tariffs are making developers and investors weary, and **could raise construction costs for new gas facilities**. LSB put their proposed 1.1Mt blue NH3 in Houston on hold in Q1 2025. Even projects beyond FID such as CF Industries, JERA and Mitsui Blue Point Complex in Louisiana could face higher costs. Tariffs may make meeting domestic content adder easier for IRA tax credits
- Although untouched and potentially benefiting from a shifting bias towards oil and gas, **blue H_2/NH_3 are also affected by the knock-on effect on the broader market**

Australia

- **Reversals of funding allocation is a risk especially at the state-level**, with re-allocation to other industries such as the $600 million Whyalla steelworks, and $1 billon Gladstone project subsidy withdrawal
- **Government support for new gas exports remains**, with a new **A$2/kg PTC for green H_2 production** launched in 2025 under purview of the new labor government
- **Australia is developing a CBAM** of their own with the same objective of preventing carbon leakage and keeping domestic industry competitive, will eventually apply to ammonia and derivatives

Key Signposts for New Gas Value Chains by Geography (2/2)

Middle East

- **Demand-side pull is the main limiting factor**, which means regions are in competition and are steadily expanding their incentive structures for new gases beyond direct investment alone, such as the UAE voluntary carbon markets and potential CfDs
- **The Hydrom Auctions in Oman are a success story.** Eight large-scale green H_2 initiatives with the potential to produce 1.38 Mtpa of green H_2 by 2030 have been awarded direct investment, land leases, tax holidays, and more in two auctions so far

North Africa

- Progress on new gas policy is uneven: rules for guarantees of origin, certification, and grid/water access are advancing but not yet uniform, and subsidy models **rely more on land, tax relief, and multilateral finance than on long-term price support**, as countries cannot bankroll multi-billion projects alone, **relying on investors in the EU and Gulf**
- **Managing water supply for electrolysis is a concern** (North Africa is water-scarce; Morocco and Egypt plan desalination for H_2). Projects must also plan for port and grid upgrades

Brazil

- **Hydrogen Legal Framework** passed Aug 2024 defines H_2 and sets a carbon-intensity cap of **7 kgCO_2e per kg H_2**. This is however quite far from the European and Japanese standards of **3.4 kgCO2e per kg H_2**, which could create misalignment
- The proposed **Low-Carbon Hydrogen Development Program** (PHBC) would create a competitive program of tax credits of up to BRL 18.3 billion ($3.4 B between 2028–2032) **to stimulate production of low-carbon H_2 and derivatives, including large-scale export FIDs**. Parts of the original bill were vetoed and are being reworked

Chile

- In August 2025, Chile proposed a bill aimed at spurring H_2 and derivative value chains with tax incentives (**$2.8 billion production tax credit for domestic purchases only to spur local demand**), **special tax regimes** particularly in the Magallanes region, and a new **Green Investment Tax Credit Fund**
- Chile's government is highly supportive of project development, granting concessions for infrastructure development (**3 alone in 2025 for Magallanes green NH_3 projects**) to **build missing infrastructure** such as port terminals, pipelines, and desalination plants

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WP1 – Regional Analysis of Readiness to Export

Including export project status and importing regions

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EU H_2 Demand

Primary Opportunities:

Europe is leading the development of global standard-setting and sustainability criteria backing their climate goals. Initial new gas uptake in the EU is supported by **REDIII RFNBO quotas primarily in the transport sector** which could be backed by **penalties of €6-10/kg H_2**. ETS & CBAM puts a price of **~$100-150/t$CO_2$** on domestically produced and imported H_2 an NH_3, especially non RFNBO

Primary Hurdles:

It appears **unlikely that industry quotas will be enforced in many major member states**, creating large uncertainty. Massive infrastructure and new technology needs, such as ammonia cracking. **Regulatory harmonization is complex and slow**

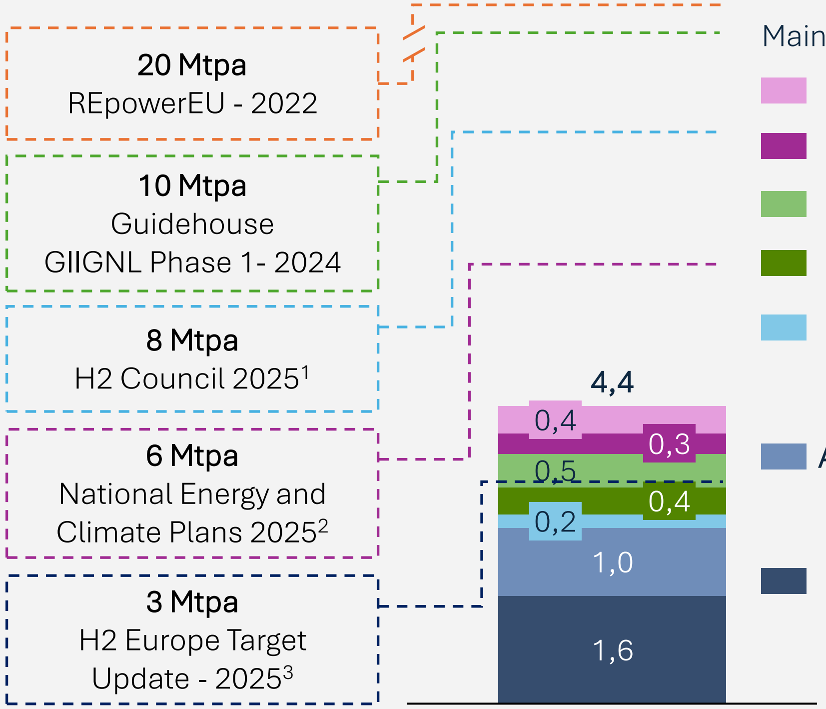
Commercial Drivers

- Particularly in Western Europe, clean gas imports are typically more **cost-competitive than domestic production**
- Avoiding over-reliance on any one supplier is a **security imperative**
- **Repurposing** of existing gas import, storage, and pipeline infrastructure networks **provides cost savings**

Developer Signposts

- **Cost competitiveness of imports is not guaranteed**; domestic production could outcompete imports in the long run
- Europe's strategy leans toward domestic biomethane production rather than importing it; some imports are expected

Clean H_2 Demand Forecasts 2030 (Mtpa H_2e)[1]



Main sectoral drivers:

- **Road:** AFIR and ETS2 carbon tax on road transport
- **Aviation:** ReFuelEU sub quota for RFNBO targets
- **Methanol:** REDIII RFNBO mandate for methanol
- **Maritime:** Fuel EU sub quota for RFNBO use in maritime
- **Steel:** DRI Investment and distribution infrastructure, however not prioritized for support for competitiveness reasons[4]
- **Ammonia:** REDIII mandated renewable ammonia; CBAM and ETS
- **Refining:** State REDIII transposition setting RFNBO 1% target; CBAM and ETS

[1]Clean hydrogen demand forecast by sector in 2030, benchmarked against other popular reports and listing key drivers. Includes imported and domestically produced renewable or low-carbon hydrogen and ammonia. Center stack largely representative of policy-covered demand with a breakeven cost of zero or less, revised down in Feb 2026 due to recent developments Hydrogen Insights. [2]Veyt [3]Hydrogen Europe [4]Commission's Action Plan

Europe's Supply Gap

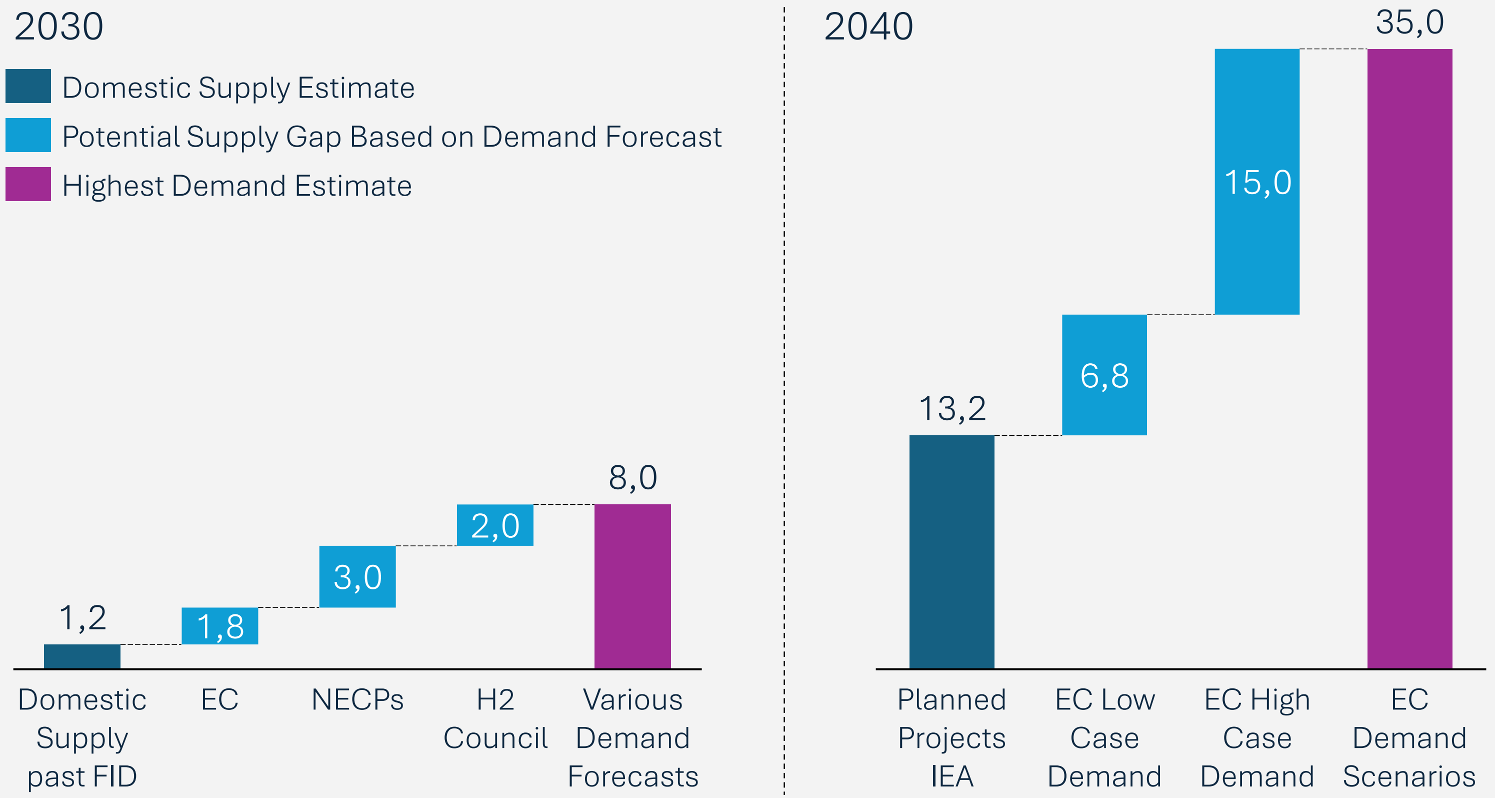
In 2022, the European Commission (EC) estimated half of the 20 Mtpa H_2 supply target would need to be imported. They have recently **revised their estimate of total demand by 2030**, but it remains unclear how much will need to be imported

Regional supply and demand imbalances are strong; delays in cross-border infrastructure bringing excess supply from Southern Europe and the Nordics to demand centers in NWE open a role for imports directly at ports in Northern Germany, the Netherlands, and Belgium. Germany has stated that **over 70% of H_2 should be imported for infrastructure and economic reasons**

Importing New Gases in Europe Remains an Imperative

Although Europe has a strong pipeline of hydrogen supply projects, it is unlikely that they will all be developed by the stated timelines (**~8% have passed FID**). The graph below shows the potential domestic supply gap that could be met either by domestic supply or imports based on various final demand projections. In the refining sector, **a supply gap of 1 Mtpa H_2** is identified based on policy-covered demand (1.6 Mtpa H_2) and committed supply and FEED capacity, **opening the door for imports**[2]

Potential Supply and Demand Gap 2030 and 2040 (Mtpa H_2e)[1]



[1]Capacity of planned projects in 2040 estimated using the IEA production project database updated March 2025, counting all projects in feasibility stage and beyond. EC demand estimates based on revised EU emissions reductions targets for 2040 Hydrogen Europe [2]Hydrogen-Council-Global-Hydrogen-Compass-2025.pdf

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EU New Gas Import Timing

The first **demo imports have occurred** – e.g. in 2022 a small cargo of blue NH_3 from the UAE was received by Germany for use in steelmaking trials

Commercial deliveries are likely to commence between 2028 and 2030: **Germany's H2Global can bring in tens of thousands of tons of green NH_3 from 2028 onward**

By 2030, Europe aims to be importing **multiple Mt of NH_3** – this relies on dozens of NH_3 ships offloading at North Sea and Mediterranean ports. E-methane imports reflect cost reductions towards 2040

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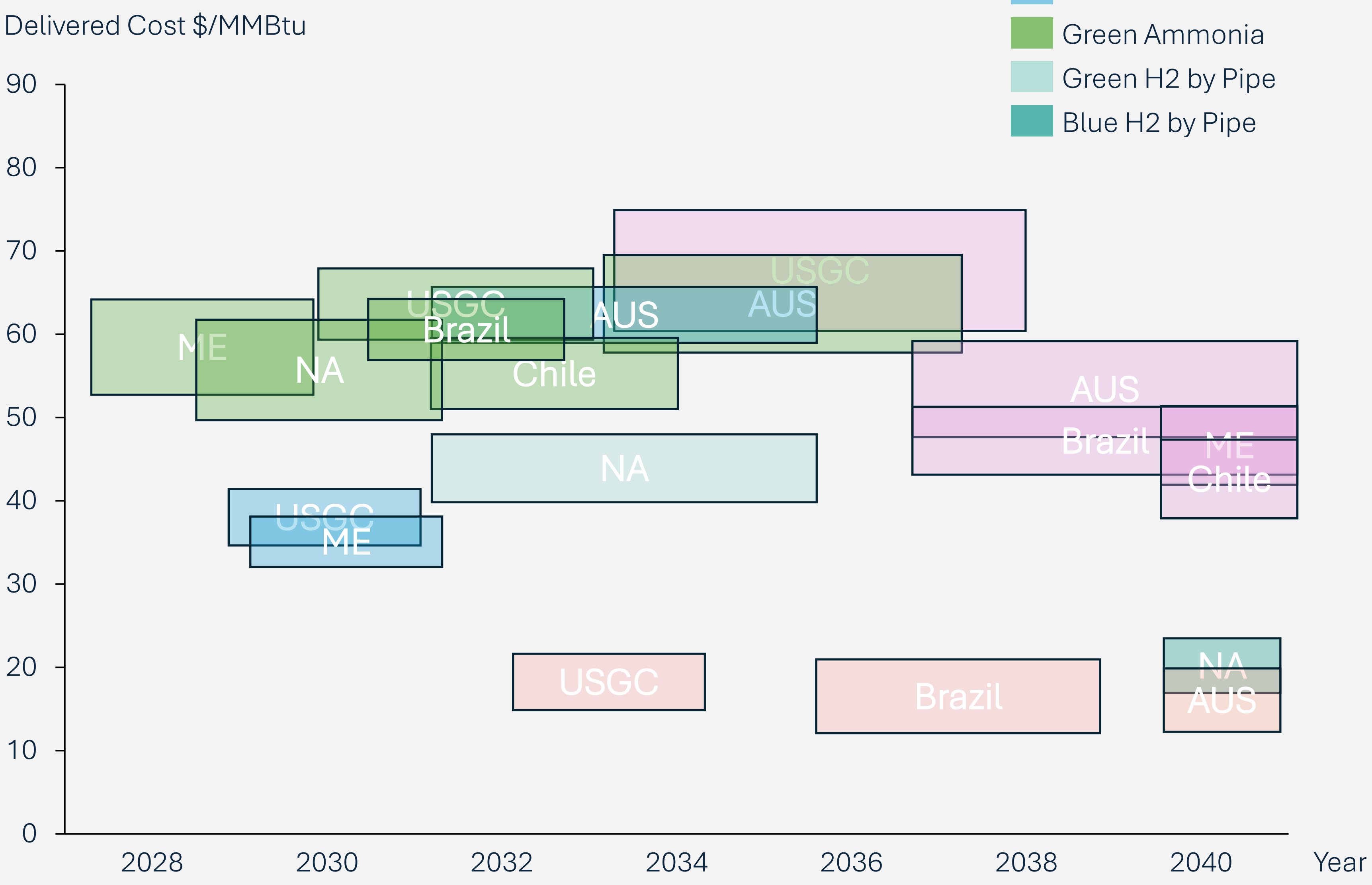
Timing and Competitiveness of New Gas Imports

Comparing gases with highest potential to export by region



[1]Range of costs captured in verticality of the square, based on high and low LCOE scenarios. Range of timeline based on horizontal spread of the square, represents the window in which there is likely to be the first commercial deliveries

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Japan H_2 Demand

Primary Opportunities:

Japan aims to leverage **existing infrastructure** as much as possible, promoting NH_3 coal co-firing and e-methane injection in existing gas pipelines and boilers. Like Europe, they are seeking a **first-movers' advantage by locking in low long term supply contracts with preferential pricing**. METI has allocated ~$51 billion for H_2 infrastructure, with ~$19 billion going to CfDs for H_2 and ammonia imports underway[2]

Primary Hurdles:

Nascent international CO_2 accounting framework and compliance markets. Safety concerns around NH_3 imports and combustion near urban centers

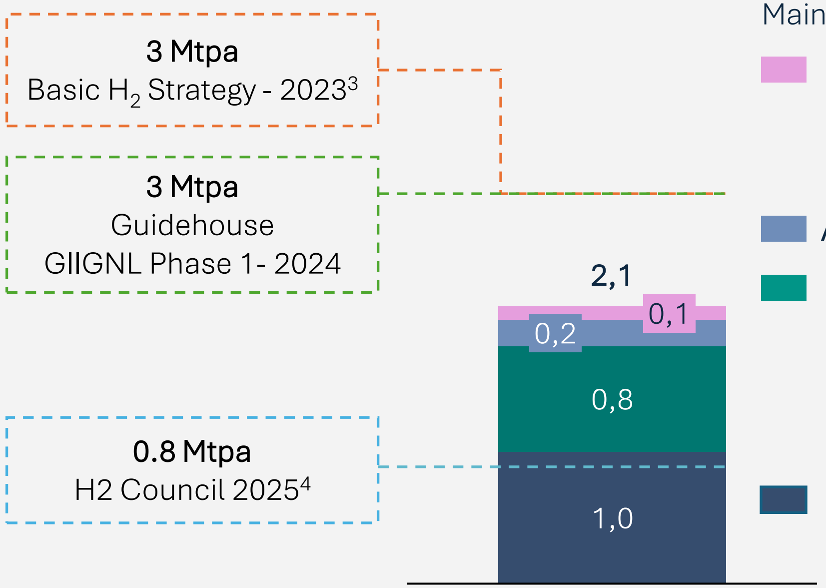
Commercial Drivers

- High-cost domestic production and land constraints make imports necessary to do cost-effective decarbonization
- **Technology innovation hub** leading H_2 turbines, FCEVs, NH_3 co-firing, H_2 carrier, and ship development, etc.
- **Extensive LNG import infrastructure** enable bio-LNG and e-methane blends

Developer Signposts

- Japanese buyers prefer long-term offtake agreements with politically stable countries and often seek **JV or equity involvement to secure supply chain stability**
- **Biogenic CO_2 for e-methane production not yet an imperative as in the EU** as current regulations see once recycled fuels as carbon neutral

Clean H_2 Demand Forecasts 2030 (Mtpa H_2e)[1]



Main sectoral drivers:

Transport: Road: station and vehicle goals (impact is minor)
Maritime: emissions caps and MEPC 80
Aviation: airlines beginning to trial SAF

Ammonia: Depends on cost competitiveness of imports

Power: Main driver of new demand
USD 19 billion CfD support over 15 years
Aiming for 1% of electricity gen. by H_2/NH_3 by 2030
Power capacity auctions – NH_3 co-fired power

Refining: Decarbonizing existing demand
Domestic and international blue H_2 and NH_3

[1]Clean hydrogen demand forecast by sector in 2030, benchmarked against other popular reports and listing key drivers. Includes imported and domestically produced renewable or low-carbon hydrogen and ammonia. Adding a potential estimate of transport demand from road, maritime, and aviation that could materialize if compliance ramps up. [2]The view from Japan [3]Japan: hydrogen strategy [4]breakeven cost of zero or less from Hydrogen Insights

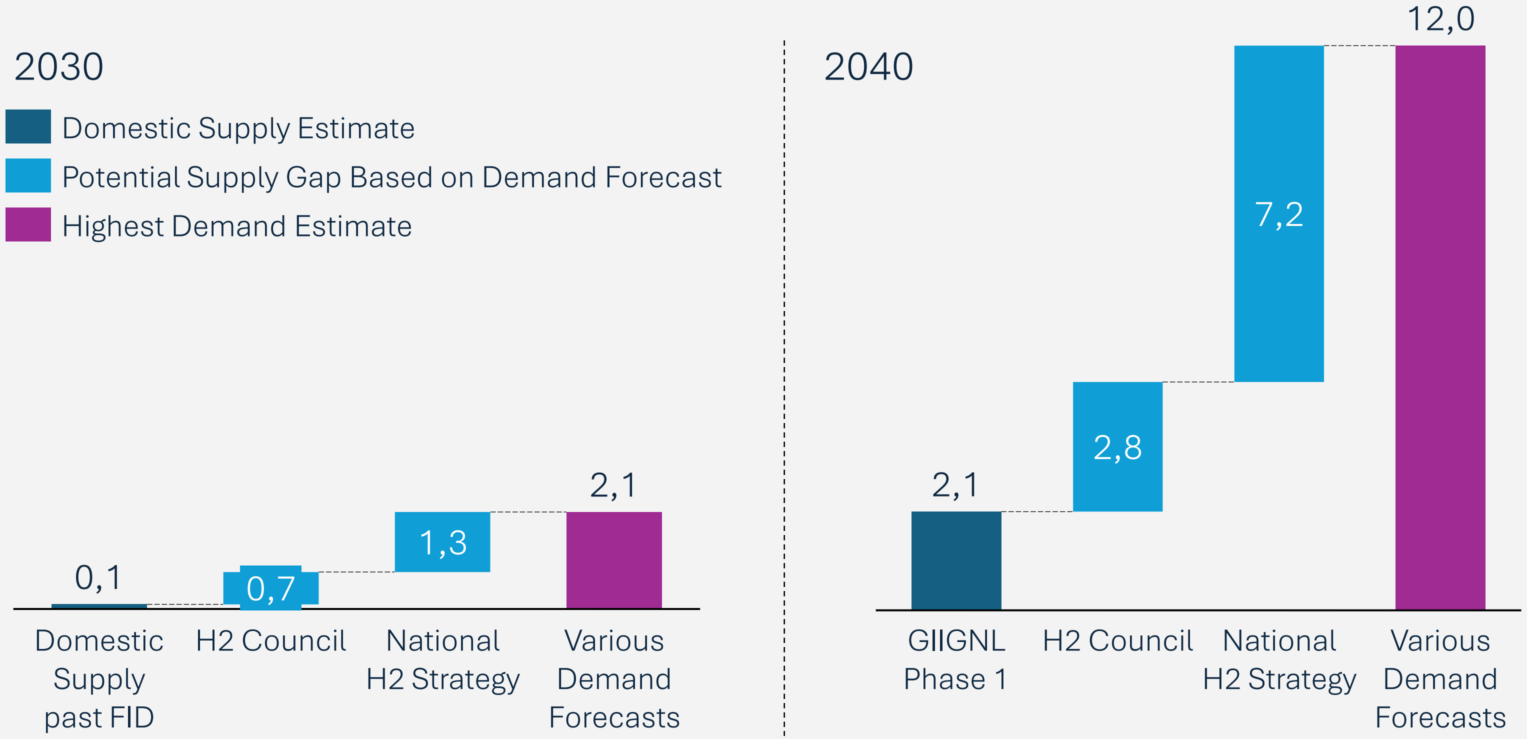
Japan's Supply Gap

Japan has minimal planned domestic new gas production projects in advanced stages, and will rely mostly on imports to meet its 2030 and 2040 demand targets, unless a surge in multiple 100MW electrolyzer plants or blue H_2/NH_3 breaks ground in the next decade. Crucially, CfD support via Japan's Clean Hydrogen Support Program covers imports as well as domestic supply. The question remains if imports can scale to the targets in time, given current support may not be enough. It is estimated that a total volume **of ~0.6 Mtpa H_2e could be unlocked through the current CfD program if spread over the 15-year lifetime of the program**

Japan Remains a Key Market for Exporters

Despite the prohibitive economics of domestic new gas production at scale, it is unclear how much H_2 and NH_3 Japan will be able to produce as no target is set and the **current pipeline of domestic project capacity is negligible**. Retrofitting existing production with CCS could be effective at reducing import infrastructure needs, but only one project is publicly announced (INPEX Kashiwazaki Blue H_2/NH_3 0.1Mtpa H_2)

Potential Supply and Demand Gap 2030 and 2040 (Mtpa H_2e)[1]



[1]Capacity of planned projects in 2040 taken from GIIGNL Phase 1 and is considered a high estimate. The H2 Council figures for 2030 consider all potential supply with a positive business case, the 2040 estimate considers the end-uses that require significant cost or infrastructure unlocks. Hydrogen Insights

Japan New Gas Import Timing

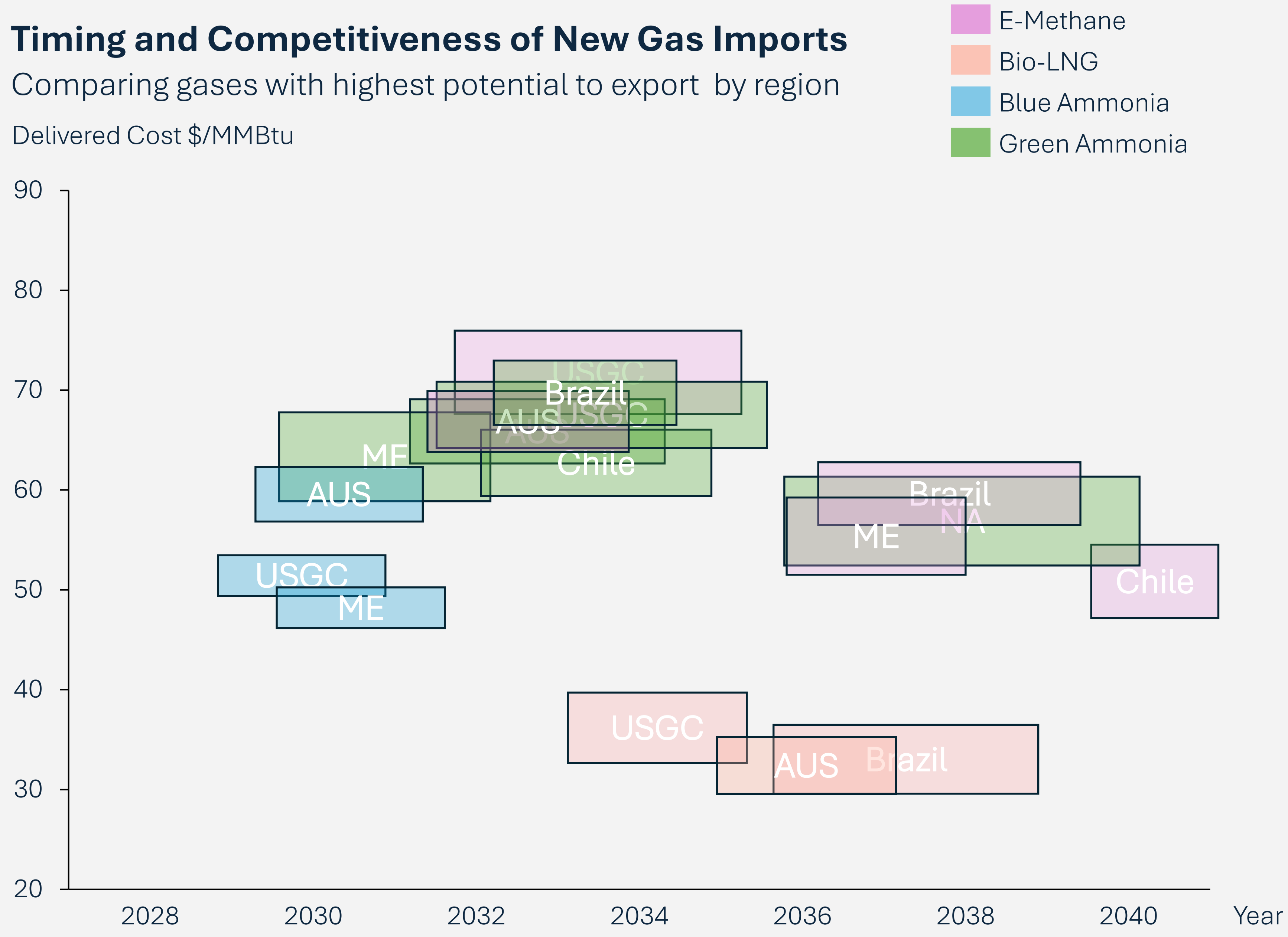
Blue NH_3 from the US and Middle East is likely to be the most cost-effective near-term import. Green NH_3 will be another key import but will require subsidization in the near term. Although not included in the cost analysis, **China could bring in the first volumes of low-cost green NH_3** to Japan around 2028 through the Enivision-Marubeni agreement

Japanese gas companies aim to inject 1% (0.6 Mtpa) of city gas demand as e-methane by 2030, which **could soon be transposed into law as an obligation by METI, supported by corresponding financial incentives**

Timing and Competitiveness of New Gas Imports

Comparing gases with highest potential to export by region

Delivered Cost $/MMBtu



[1]Range of costs captured in verticality of the square, based on high and low LCOE scenarios. Range of timeline based on horizontal spread of the square, represents the window in which there is likely to be the first commercial deliveries

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US Gulf Coast

EXPORT SCORE[1]: 8.1

Primary Opportunities:

Accelerating permitting and investment for LNG could benefit the development of bio-LNG, blue ammonia, and e-methane supply chains through infrastructure

Primary Hurdles:

Tax credit rollbacks are hindering renewables and green H_2 projects, as they **must begin construction by 2028 instead of 2033 to qualify for 45V tax incentives.** (Air Products $4B project canceled, HIF Global $7B hub put at risk). $2.2B in funding was pulled in October foe the ARCHES and PNWH2 projects.

Commercial Drivers

- World-class port infrastructure, existing **gas, H_2, CO_2 and NH_3 pipelines**, and a skilled industrial workforce
- Abundant **low-cost natural gas, strong wind and solar resources** in Texas and Louisiana

Developer Signposts

- **Strong competition for biogenic CO_2** from the carbon removal market from players like Microsoft, which are willing to pay upwards of $200/$tCO_2$[3]
- Methanol, e-fuels, and direct air capture plants are also being widely developed to serve **local markets and export**

Most Attractive Export Supply Chains

New Gas	Destination	Timeline[2]	Drivers
Blue Ammonia	1. Asia 2. Europe	2029	Since 2022, the US has ramped up NH_3 exports with over 1Mtpa in 2025, increasingly supplying Europe. Ample CCS infra and incentives drive a pipeline of **11 blue NH_3 projects planned**[4]
Green Hydrogen & Ammonia	1. Europe 2. Asia	2030	Further behind than blue NH_3 development, planned projects threatened by early 45V sunset. **5 projects in planning, none with FID**
E-Methane	1. Asia 2. Europe	2030	Shipments to Japan from the **Cameron LNG facility could start as early as 2030 if FID is attained in 2026**, hinging on 45V and Cameron phase 2 expansion[5]
Bio-LNG	1. Europe 2. Asia	2032	Local biomethane incentives outcompete export opportunity, pilot ran in 2024 for Tokyo Gas from Cameron. **EU demand likely stronger than Japan due to market premium and shared gas grid**

[1]Readiness to export score based on holistic assessment on new gas supply chains commercial and policy drivers. Detailed scoring follows. [2]Expected start of commercial shipments. [3]Microsoft carbon removal [4]Ammonia in the US [5]Japan's e-methane plan

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US Gulf Coast – Status of Notable Projects

US Gulf Coast has a dynamic mix of new gas projects with blue ammonia projects reaching FID

Name	New Gas	Stage	Capacity[1]	Start	Partners	Description
Blue Point Ammonia JV	Blue Ammonia	FID reached 2025	~1.4 million t/yr NH_3	2029	CF Industries (40%) JERA (35%) Mitsui & Co (25%)	Each partner will lift NH_3 proportional to ownership – JERA and Mitsui intend to ship to Japan. Construction integrates CCS via 1PointFive's Pelican CCS hub (2.3 Mt CO_2/yr).[3]
Baytown Blue NH_3	Blue Ammonia	FID reached 2025	~1 million t/yr NH_3	*Put on indefinite pause*	ExxonMobil Marubeni	Offtake signed for 250,000 tons of blue NH_3 produced in Baytown for 20% co-firing at Kobe power plant.[4] Developers cite 45V reductions as a major risk to broader market demand and put project on pause
Louisiana Clean Energy Complex	Blue Ammonia	Pre-FID, no offtake for NH_3 yet	620,000 t/yr H_2	2029-2030	Air Products	A portion of the H_2 will feed Air Products' Gulf Coast pipeline, the rest converted to blue NH_3 for export. Air Products looking to divest from CCS and NH_3 production.[2]
HyVelocity Hub	Green and Blue H2/ Ammonia	Pre-FID (expected 2025)	~1.46 million t/yr NH_3	2035	AES, Air Liquide, Chevron, Ørsted, Exxon, and more	HyVelocity Hub will integrate 9 major H_2 projects in Texas/Louisiana, focusing on exportable products like NH_3 and fuels.[2] DOE Hub award, at risk of losing funding.[5]
Hydrogen City	Green Ammonia	Early Feasibility	~15 million t/yr NH_3	2028 (1st phase 2.2GW elz)	Green Hydrogen International, Inpex	Up to 60 GW of wind/solar powering electrolyzers. Aiming for Asian ammonia markets, as well as domestic SAF and fuel switching. Originally planning to start their first phase in 2026, earliest likely 2028 to make 45V eligibility.
ReaCH4	E-Methane	FEED, FID planned 2025	130,000 t/yr	2030	Tokyo Gas, Osaka Gas, Toho Gas Mitsubishi, Sempra	Liquifying via existing Cameron LNG terminal (requiring expansion) intended for Japan's city gas market, blending into LNG supply for utilities.[6]

[1]Annual output at scale [2]Air Products [3]CF, Mitsui & JERA [4]Marubeni & Exxon [4]HyVelocity [5]Green Hydrogen International Projects [6]meti.go.jp

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Australia

EXPORT SCORE[1]: 6.3

Primary Opportunities:

Highly versatile region with potential to export blue and green hydrogen, ammonia, bio-LNG and e-methane at **competitive prices primarily to Asian markets**

Primary Hurdles:

Distance to Europe, high domestic capital costs. **Several projects shelved or delayed due to cost and feasibility issues**. State funds being allocated to other industries such as the $600 million Whyalla steelworks, and $1 billon Gladstone project subsidy withdrawl[4]

Commercial Drivers

- Experience in handling bulk energy commodities - leading LNG exporter
- **Heavy commercial ties with Japanese and Korean companies** investing in Australian projects (e.g. the Kawasaki Hydrogen Energy supply chain) due to resources and land availability

Developer Signposts

- Developers must engage early and deeply with **Traditional Owners** to secure **long-term social license**. Heritage issues have caused delays and reputational risk (e.g., Nullarbor – Western Green Energy Hub, Traditional Owners hold 10% stake and must grant approval to develop[3])

Most Attractive Export Supply Chains

New Gas	Destination	Timeline[2]	Drivers
Green Hydrogen & Ammonia	1. Asia 2. Europe	2030	Liquified H_2 pilots already shipped to Japan in 2022, but no major FIDs yet, pre-2030 commercial exports likely delayed. Can produce very competitive gas, especially with **new production tax credits**
Blue Ammonia	1. Asia 2. Europe	2029	Pilot exports of blue NH_3 shipped to Japanese utilities in 2022. **Four main blue hydrogen/ammonia export projects in advanced pre-FEED or FEED stages**. First exports anticipated between 2028 and 2029[5]
E-Methane	1. Asia	2030	**Santos project progressing** driven by Japanese gas consortium. No other major projects planned
Bio-LNG	1. Asia 2. Europe	2035	Bio-LNG export is not yet pursued. May come via companies like Woodside, which is investigating carbon-neutral LNG cargoes, **however costs are high**

[1]Readiness to export score based on holistic assessment on new gas supply chains commercial and policy drivers. Detailed scoring follows. [2]Expected start of commercial shipments. [3]First Nations Clean Energy Network [4] The Guardian
[5] Western Australia blue ammonia project

GIIGNL

Australia – Status of Notable Projects

Australia's has a long-term vision for new gas exports, no mega projects have reached FID yet

Name	New Gas	Stage	Capacity[1]	Timeline	Partners	Description
FFI and E.ON Supply to Europe	Green Hydrogen	Pre-FID (expected 2025)	22 million t/yr H_2	2030	Fortescue Future Industries and E.ON	Hydrogen supply & distribution agreement signed between Fortescue and E.ON in Germany. FFI invested in Wilhelmshaven import terminal to be operated by TES[2]
Western Green Energy Hub – Eucla	Green Ammonia	FID expected 2029	22 million t/yr NH_3	Early 2030s	InterContinental Energy, CWP Global, Mirning Green Energy Limited (MGEL)	At full scale, wind and solar capacity planned at 70GW, taking place over seven phases taking approximately 30 years to complete. MoU with KEPCO for phase one development (6-8 GW of hybrid RES, 333,000 tonnes H_2)[3]
WAH2	Blue Ammonia	Pre-FEED / FEED	600,000 t/yr NH_3	2029	Hexagon Energy Materials, Chevron	Chevron Australia will supply gas for an initial 10 years with a potential five-year extension. Targeting bunkering (MoU with Oceania Marine Energy) and export to Asia.[4]
Mid West Clean Energy Project	Blue Ammonia	Pre-FEED / FEED	1 million t/yr NH_3	2029	Pilot Energy, Korean consortium of Gencos & Energycos	NH_3 for co-firing in coal-fired power plants and industrial consumption in Korea. The Korean consortium currently seeking to enter an equity partnership and offtake[5]
Santos and Japanese Gas Consortium E-Methane	E-Methane	Pre-FEED agreement signed Aug 2024	130,000 t/yr e-methane	2030 at the earliest	Santos with Tokyo Gas, Osaka Gas, and Toho Gas	Renewable hydrogen in the Cooper Basin (central Australia), combined with CO_2 (from Santos's Moomba CCS or DAC) to create e-methane and transport via existing gas pipelines to Darwin LNG and Gladstone LNG terminals for use in Japan city gas. METI Subsidized[6]

[1]Annual output at scale [2]Fortescue [3]Western Green Energy Hub [4]chevron clean ammonia project down under [5]Mid West Clean Energy Project [6]osakagas

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Middle East

EXPORT SCORE[1]: 8.7

Primary Opportunities:

Oil and gas players in major Gulf States (Saudi Arabia, UAE, Qatar, and Oman) see new gas supply chains as an **imperative to maintain energy exports in a decarbonizing world.** Strategic location allows competitive distance to European and Asian markets. Trial shipments to Asian markets have built trust and expertise. **Expected to bid in upcoming Japanese and Korean auctions for H_2 and derivatives**

Primary Hurdles:

Instability in the region poses threats to shipping lanes.[3] Lacks biomass resource for biogenic CO_2 and bio-LNG

Commercial Drivers

- **Abundant cheap natural gas** to produce blue H_2/NH_3 and **vast desert areas** with **some of the world's highest solar irradiance** and **high-capacity-factor wind sites** (e.g. Oman's Dhofar region, Saudi Arabia's Red Sea coast) for green H_2-based molecules
- Experience with energy mega projects and a **conducive business environment**

Developer Signposts

- Exclusive land use rights and permits are **controlled centrally**
- Developers need **strong sovereign partnerships** and offtake certainty for FID
- Water must be desalinated for electrolysis, but costs are minimal given low electricity prices
- Increasing share of production expected to go towards domestic demand (primarily UAE), **may undercut export potential**[4]

Most Attractive Export Supply Chains

New Gas	Destination	Timeline[2]	Drivers
Green Hydrogen & Ammonia	1. Europe 2. Asia	2027	**NEOM green H_2 export project at 90% construction as of Jan 2026**, with preliminary agreements signed with European offtakers expected 2027.[5] Oman has many seven large projects expecting FID in 2026-2027
Blue Ammonia	1. Asia 2. Europe	2029	UAE's ADNOC and Saudi firms **pilot cargoes to Japan** (2021–2022) and to **South Korea and China** (2023). Qatar investigating projects (ammonia-7 program, FEED underway)
E-Methane	1. Asia 2. Europe	2035	Tokyo Gas , Osaka Gas, Masdar and INPEX conducting a feasibility study in Abu Dhabi. **Likely to lag behind US and Australia in the near term**

[1]Readiness to export score based on holistic assessment on new gas supply chains commercial and policy drivers. Detailed scoring follows. [2]Expected start of commercial shipments. [3]TRACKER [4]S&P Global [5]80% Completion

GIIGNL

Middle East – Status of Notable Projects

By 2030, Middle East exports of clean hydrogen (mostly as ammonia) could reach ~0.8 Mt H_2 equivalent

Name	New Gas	Stage	Capacity [1]	Timeline	Partners	Description
NEOM Green Hydrogen - Saudi Arabia	Green Ammonia	FID reached 2023	1.2 million t/yr NH_3	2027	ACWA Power, Air Products, and NEOM	World's largest green NH_3 project under construction: 4 GW of solar/wind and 2.2 GW electrolysis, with some 23 banks and investment firms providing $8.4 billion in finance. Air Products has an exclusive 30-year offtake agreement and is lining up supply agreements in Europe. [2] Air Products has slowed its investments into NH_3 cracking in Europe, and will focus on FOB NH_3 delivery until 2030
HYPORT - Duqm, Oman	Green Ammonia	FID expected ~2026–27	1.2 million t/yr NH_3	2030	OQ Alternative Energy, BP, Deme	Oman's first H_2 export project in development. Uniper (Germany) has an MoU for offtake, initial phase could deliver 330,000 t/yr green NH_3 to Germany before 2030[3]
ACME Duqm Project - Oman	Blue Ammonia	Pre-FID Construc-tion started 2022	0.9 million t/yr NH_3	2029	ACME (India), Scatec (Norway)	Project closed financing in July 2023 for a first phase, backed by Rupee 40 billion from REC (India). Binding term sheet agreement with Yara, to be formalized into an offtake agreement for likely the entire output from phase one[4]
TA'ZIZ Blue Ammonia - Ruwais, UAE	Blue Ammonia	FID reached 2022	1 million t/yr NH_3	2030	ADNOC (through Fertiglobe – its JV with OCI), Mitsui & Co, and GS Energy	NH_3 production expected by 2027, with clean ammonia coming online by 2030 for export to Korea and Japan. Trial shipments of blue NH_3 already shipped to Mitsui and GS by ADNOC[5]

[1]Annual output at scale [2]NEOM [3]Oman's First Green Hydrogen Project [4]S&P Global [5]MITSUI & CO., LTD.

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North Africa

EXPORT SCORE[1]: 3.9

Primary Opportunities:

New gases can monetize renewables at scale and attract foreign investment for domestic industrial development (e.g. green steel, fertilizers) alongside export. **Proximity to Europe** is a major advantage. **Gas pipeline connections** could be repurposed (Medgaz or TransMed)

Primary Hurdles:

Nascent regulatory frameworks and investor clarity on contracts, land leases, and profit repatriation. **Water scarcity** means desalination will be needed for electrolysis (Egypt investing in desalination and using Nile water for pilots), but could pose problems politically

Commercial Drivers

- Algeria and Egypt hold **sizable gas reserves**, **operate LNG export terminals**, and a **network of gas pipelines**
- North Africa has **major ports on the Mediterranean** (Tangier, Alexandria) that could be adapted for H_2/NH_3 shipping
- Sahara offers solar **irradiance comparable to the Arabian Desert.** Coastal areas have good wind regimes

Developer Signposts

- Projects must plan for **port and grid upgrades**, **limited water supply**, and **political stability concerns in some places**
- Bureaucracy can delay large investments
- Access to EU markets is strong via MoUs and hydrogen diplomacy, **but competition is stiff**, and financing requires guarantees
- Biomass resources are limited outside of the Nile Delta, any biomethane likely to be consumed domestically

Most Attractive Export Supply Chains

New Gas	Destination	Timeline[2]	Drivers
Green Hydrogen & Ammonia	1. Europe 2. Asia	2028	H2Global import tender award to Fertiglobe for green NH_3 export from Egypt to Northwest Europe, **originally expected 2027 but FID delayed**. Morocco and Tunisa expected to follow closely (2030) if infrastructure such as the **SoutH2 pipeline** connecting Tunisia and Italy is built[3]
Blue Hydrogen	1. Europe	2040	Only mention of blue H_2 in the region is Algeria's national strategy, **which targets 0.9–1.2 Mtpa of clean hydrogen (green or blue) by 2040**, and includes discussions of pipeline export to Europe. However, by then, blue H_2 may not be admissible in Europe

[1]Readiness to export score based on holistic assessment on new gas supply chains commercial and policy drivers. Detailed scoring follows. [2]Expected start of commercial shipments. [3]Tunisia's first H2 exports to Europe by 2030

GIIGNL

North Africa – Status of Notable Projects

The EU is expected to import up to 0.5 Mt H_2 from North Africa by 2030, all major projects are RES based

Name	New Gas	Stage	Capacity[1]	Timeline	Partners	Description
Fertiglobe EBIC - Ain Sokhna	Green Ammonia	H_2 production FID expected 2nd half 2025	63,000 t/NH_3	2028	Fertiglobe (ADNOC and OCI), Scatec, Egypt Green Hydrogen	Supply volume from Egypt is projected to start at 19,500 tons in 2027, and then average ~63,000 tons between 2028 and 2033 at a price of ~€1000 per t/NH_3. FID of Egypt Green Hydrogen plant delayed from 1st half 2025 to H2 by Scatec, construction may carry on beyond 2027 without jeopardizing the offtake contract in place with H2Global[2]
EDF / Zero-Waste Project - Ras Shokeir	Green Ammonia	Agreement signed April 2025	1 million t/NH_3	2030	EDF Renewables, Zero-Waste in partnership with Egyptian authorities	Phase 1 (by ~2026) will output 300,000 t/yr NH_3. Project includes an export jetty and infrastructure for ammonia shipping, feasibly for European utilities. Now in development & financing stage (fully private-funded, ~€7 billion total)[3]
Hevo Ammonia - Jorf Lasfar, Morocco	Green Ammonia	Feasibility	183,000 t/NH_3	2030	Fusion Fuel, CCC	Set to be Morocco's first green NH_3 exports to Europe also supply state-owned OCP for green fertilisers. Initial start date was 2026, but updates have been scarce since announcement in 2021[4]
Aman Project – Mauritania	Green Ammonia	FID expected 2030	10 million t/NH_3	2035	CWP	30 GW wind and solar project CWP Global has recently reaffirmed its commitment to the Aman green hydrogen project in Mauritania[5]

[1]Annual output at scale [2]Egypt Green Hydrogen project delayed [3] Egypt and France Ink €7 Billion Deal [4]H2diplo [5]CWP Reaffirms Project Commitment

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Brazil

EXPORT SCORE[1]: **4.9**

Primary Opportunities:

Brazil's northeast coastline offers ideal sites for co-located wind farms, electrolyzers, and export terminals. **Low-CI grid makes Brazil naturally competitive in light of EU Delegated Acts, potentially exempting projects from the additionality clause.** Strong diplomatic ties with the EU (Mercosur) and Japan (largest Japanese diaspora and energy investments)

Primary Hurdles:

Bureaucratic delays, permitting challenges, and occasionally local opposition. Fiscal situation could limit public co-investment or tax breaks

Commercial Drivers

- Has the **lowest carbon intensity grid** of all exporters included in the study (dominated by hydropower)
- Untapped wind and solar potential with some of the **highest onshore wind capacity factors** globally (42-60%)[3]
- Plentiful biomass and biogas resources for bio-LNG or e-methane, but liquefaction infra. Is absent

Developer Signposts

- Brazil is a top exporter of iron ore and has potential to use H_2 in value-added form to **produce green steel for export**
- Intermittency of power for large-scale projects means hydro-powered grid connection is needed; **droughts have affected power reliability in the past**
- Capital costs in Brazil are typically higher than other markets in scope

Most Attractive Export Supply Chains

New Gas	Destination	Timeline[2]	Drivers
Green Hydrogen & Ammonia	1. Europe 2. Asia	2030	Pecem (Ceara state) projects aim for operation by 2028-2030, and multiple other ports (Açu, Suape) could be shipping to Europe and Asia by 2030 if MoUs become contracts (interest signaled by Japan's METI). **EU support is strong, aligning with RFNBO standards**
E-Methane	1. Asia 2. Europe	2035	Brazil has ample CO_2 resources from ethanol fermentation, with some methanol projects in development. **Lack of export infrastructure for CH_4 is the largest barrier, no projects currently planned**
Bio-LNG	1. Europe 2. Asia	2035	Extensive biomass means bio-LNG exports are plausible. **First bio-LNG project launched Aug 2025** by Furui Energy for the local market, which is driven by vehicle fuel and industrial use[4]

[1]Readiness to export score based on holistic assessment on new gas supply chains commercial and policy drivers. Detailed scoring follows. [2]Expected start of commercial shipments. [3]Brazil Factbook [4]Furui Energy

Brazil – Status of Notable Projects

Pecém port area leading development with 40+ MoUs signed and investment from the World Bank, ITA, CIF

Name	New Gas	Stage	Capacity[1]	Timeline	Partners	Description
H2 Cumbuco – Pecém	Green Ammonia	FID expected 2025	~1.6 million t/yr NH_3	2030 (0.4 t/yr)	FRV, Utilitas Pecém, PB Construções	Sixth renewable ammonia project announced for Ceará state. USD 5 billion project planning RFNBO aligned ammonia export using treated urban wastewater[2]
Project Iracema – Pecém	Green Ammonia	FID expected 2025	~2.2 million t/yr NH_3	2030 (0.4 t/yr)	Casa dos Ventos, Comerc, TransH2 Alliance	Transhydrogen Alliance (Dutch firm Proton Ventures and trader Trammo) intends to ship ammonia to Rotterdam for off-takers in Europe[3]
TotalEnergies and CDV – Pecém	Green Ammonia	FID expected 2026	0.9 million t/yr NH_3	2030	Casa dos Ventos, TotalEnergies	Potential USD 5 billion export project supporting TotalEnergies' plan to replace 500,000 tons of gray hydrogen with green hydrogen in its EU refineries by 2030[4]
Solatio H2V – Piauí	Green Ammonia	FID expected 2025	3x1GW electrolyser phases	2030	Solatio, H2V	USD 4.7 billion H_2 and exportable NH_3 project approval from the Brazilian Ministry of Mines and Energy for a 3 GW grid connection with over 90% of renewable power[5]
Green Energy Park – Piauí	Green Ammonia	FID expected 2026	2.1 million t/yr NH_3	2035	Green Energy Park	Accompanied by the Industrial Transition Accelerator, adding credibility and aiming for FID before COP 30. EU and Asian export and potential domestic steel plays[6]
YamnaCo – Port of Açu	Green Ammonia	Feasibility (FID 2027)	1 million t/yr NH_3	2030	YamnaCo, Port Açu authorities	Land reservation agreement signed in March 2025, project benefits from deep port draft and direct quay access[7]

[1] Annual output at scale [2] Cumbuco [3] Project Iracema [4] TotalEnergies [5] Solatio H2 Piauí [6] Green Energy Park [7] Yamna

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Chile

EXPORT SCORE[1]: 5.1

Primary Opportunities:

If realised, the projected $25 billion export market by 2050 would be similar scale to Chile's mining industry, (60% of Chile's exports and 12% of GDP). **Push to replace ammonia imports and copper exports**

Primary Hurdles:

Significant construction and services provision required. In windy Magallanes (Patagonia), where a third of projects are planned, new roads (120 km highway), port expansions, and airport upgrades are needed to support construction. Large export position mean large dependency on international offtake

Commercial Drivers

- **Solar capacity factors up to 37%** (Atacama), **wind 60 to 70% on and offshore** (Magallanes), with strong capacity growth in both technologies
- Largest number of free trade agreements in the world (34 with 65 economies), high political stability, and existing engineering expertise from the mining sector

Developer Signposts

- Pacific and Atlantic shipping lanes facilitate exports to Asia and Europe
- Long permitting timelines; environmental approvals must consider Patagonian ecosystems and community consultation, **although a bill was passed recently to reduce by 30-60% for H_2**
- Notable political consensus on green H_2's importance and desire to remain an energy exporter, considering the expected plateau in copper exports

Most Attractive Export Supply Chains

New Gas	Destination	Timeline[2]	Drivers
Green Hydrogen & Ammonia	1. Europe 2. Asia	2030	Green ammonia and methanol are the primary vectors for export with a pipeline of projects in environmental assessment of **5.7 million tNH_3/yr, predominantly for Europe**. No export projects in FID yet[3]
E-Methane	1. Asia 2. Europe	2040	**CO_2 sources are scarce for e-methane production,** especially where renewables capacity factors are high in the north and south, not current plans. **Could be an attractive region in the future**
Bio-LNG	1. Europe 2. Asia	2040	No existing LNG export, and a small but emerging biomethane sector with a technical potential of only around 5–7 TWh/year. **Not likely to see exports within this decade**

[1]Readiness to export score based on holistic assessment on new gas supply chains commercial and policy drivers. Detailed scoring follows. [2]Expected start of commercial shipments. [3]mfat.govt.nz

Chile – Status of Notable Projects

Projects center on green NH_3 and synthetic methanol, FIDs expected 2025-2027 depending on offtake

Name	New Gas	Stage	Capacity[1]	Timeline	Partners	Description
H2 Magallanes	Green Ammonia	Aiming for FID 2027	1.9 million t/yr NH_3	2030	TE H2 MAG (TotalEnergies)	Permitting begun for USD 16 billion export project with wind turbines, electrolyzers, and port terminal. Agreements signed in 2022 with VNG & Vertrieb Germany[2]
HAU – Magallanes	Green Ammonia	Pre FEED- Aiming for FID 2026	1.3 million t/yr NH_3	2030	HNH Energy (Daish-Austrian consortium)	Project in environmental assessment, port infrastructure included in USD 11 billion project cost. Trammo signed an MoU for all volumes of NH_3 from the project in 2021.[3]
Inna – Antofagasta	Green Ammonia	Early Stages	116,000 t/yr NH_3	2030	AES Andes	Environmental impact assessment submitted for USD 10 billion wind and solar powered hydrogen project for domestic use and export. MoU with Samsung C&T[4]
HyEx – Antofagasta	Green Ammonia	Aiming for phase 2 FID 2027	0.7 million t/yr NH_3	2030	Engie and Enaex	Solar-powered for domestic mining sector, eyeing export in phase two. in Peru, Enaex operates one of the largest pure electrolysis fed NH_3 production units and has developed a method in standby mode for several hours[5]
HIF: Haru Oni and Cabo Negro Patagonia	E-Methanol	Demonstration since 2022	174 kt/yr methanol (phase 2)	2028	HIF Global, Siemens Energy, Porsche, and ENAP	Pilot shipments sent to Porsche in Germany for use in motorsport and showcase purposes converting e-Methanol into e-gasoline. CO_2 obtained using DAC. Phase 2 offtakers could include Idemitsu Kosan (Investor), Mitsui O.S.K. Lines (LOI) and Airbus[6]

[1]Annual output at scale [2]TotalEnergies [3]Hydrogen Insight [4]AES Andes [5]HyEx: ammonia from the Chilean desert [6]Haru Oni: Fuel from Wind and Water

Readiness to Export Scoring

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Readiness to Export – Scoring Framework Rubric

Scoring framework used to rank exporting regions on strength as potential new gas exporters by 2030-2035, scores are designed for relative comparison of the specific regions and gases in scope to give separation

Criteria	Weight	Score: 1	4	7	10
Competitive-ness of LCOx	25%	**Highest Cost:** Region has the highest average LCOx in 2030 for most gases in scope	**Higher Cost:** Among the regions with average LCOx higher than the average for gases in scope, but not highest	**Lower Cost:** Among the regions with average LCOx lower than the average for gases in scope, but not lowest	**Lowest Cost:** Region has the lowest average LCOx in 2030 across all gases in scope
Policy Support[1]	25%	**Policy Laggard:** Least number of incentives available, high regulatory barriers for new gas export	**Regulatory Barriers:** Some incentives available, some regulatory barriers for new gas export	**Regulatory Tailwinds:** Large number of incentives available, minimal regulatory barriers for new gas export	**Policy Leader:** Highest number of incentives available, almost no regulatory barriers for new gas export
Commercial Development	20%	**Commercial laggard:** Region has either the smallest project pipeline and least committed investment	**Slow Starter:** Among the countries with a project pipeline and committed investment below the average	**Strong Development:** Among the countries with a project pipeline and committed investment above the average	**Market Leader:** Leading either by project pipeline and committed project investment
Availability of Feedstocks[2]	15%	**Feedstock Constraints:** Least competitive and accessible new gas feedstocks	**Limited Feedstocks:** Below-average competitiveness and availability of feedstocks	**Feedstock Adequacy:** Above-average competitiveness and availability of feedstocks	**Feedstock Abundance:** Most competitive and accessible new gas feedstocks
Infrastructure Constraints	15%	**Infrastructure Constraints:** Most crucial infrastructure related to electricity, pipeline and export are lacking	**Basic Infrastructure:** Some crucial infrastructure related to electricity, pipeline and export are in place	**Strong Infrastructure:** Most crucial infrastructure related to electricity, pipeline and export are in place	**Infrastructure Drivers:** All crucial infrastructure related to electricity, pipeline and export are widespread

[1]Determined in WP2 regulatory framework comparison [2]RES, biomass, and natural gas supply availability and cost, evaluated using GIIGNL Phase 1 WP1 report

Readiness to Export – Scoring Framework Results

US Gulf Coast and Australia are similarly positioned as suppliers of almost all new gases

	US GC	Explanation
Overall Score	8.1	
LCOx	7	Average LCOx across gases in scope is below average, owing to solid RES, natural gas and biomethane resource.
Policy Support	7	45V PTC gives the strongest incentive for green H_2 production globally but has been reduced along with DOE H_2 Hub program. Regional incentives and 45Q remain, showing priority for CCS and CH_4 supply chains
Feedstocks	7	Widely available mix of renewables, gas, biomethane, and Bio-CO_2. One of the largest but fast interconnection queue for renewables. Costs and capacity factors higher.
Infrastructure	10	Existing gas pipeline, liquefaction, port, ammonia, CCS infrastructure can be repurposed for production and export of all new gases
Development	10	Robust pipeline of projects, over 67 green H_2 projects US-wide through 2029, many in the Gulf Coast[1] ~3 E-methane projects in early stages. Widespread domestic biomethane production

	Australia	Explanation
Overall Score	6.3	
LCOx	4	Highly competitive green molecule-based value chains, most competitive e-methane using hybrid RES, however highest natural gas costs.
Policy Support	7	New production tax credit of A$2 per kg (≈$1.3/kg). Several grant programs (e.g. ARENA funding) and state-level hydrogen strategies bolster export development, but total incentive support is much less than the US
Feedstocks	7	Exceptional solar, wind, and natural gas resources as well as land availability. Biomethane mostly from waste resources. Availability tends to be lower give distance.
Infrastructure	7	Strong LNG export infrastructure and industrial deep-water ports preparing for liquid hydrogen and ammonia export. Ammonia export and storage infrastructure needs to be built.
Development	7	Over 80 green hydrogen projects amounting to 10 million tons, largest pipeline of hydrogen projects by capacity. Many being delayed, and no mega projects have reached FID[2,3]

[1] Green Hydrogen Projects [2] DCCEEW [3] Hydrogen Insight

Readiness to Export – Scoring Framework Results

Middle East is a leader across all criteria. Proximity to Europe is a key strength for North Africa

Middle East		Explanation
Overall Score	**8.7**	
LCOx	7	Lowest LCOH for diurnal hybrid res and pure solar configurations. Pure solar powered is lower cost than Chile despite having lower capacity factors, since profile is more consistent throughout the year and less H_2 storage is needed. Lowest natural gas costs lead to lowest blue H_2 and NH_3
Policy Support	10	Seen as a strategic priority in countries like Oman, Saudi Arabia, UAE. State-led investments, offering cheap land and capital to developers, who face few regulatory hurdles. Government support could undercut even US-subsidized levels[1]
Feedstocks	10	World leading solar and wind resources as well as some of the largest natural gas resources. No useful biomass resource
Infrastructure	10	Extensive gas pipeline networks, LNG export terminals, and ammonia/fertilizer complexes (Qatar, Oman, UAE, Saudi Arabia). UAE building a 1,400 km hydrogen pipeline network by 2030
Development	7	Relatively small project pipeline, but is a leader in committed project investment at around 1.4 Mt H_2 in advanced stages (40% of global capacity under construction)[1]

North Africa		Explanation
Overall Score	**3.9**	
LCOx	7	With capital costs held equal, high solar irradiance and wind capacity factors, especially in places like Egypt and Southern Morocco drive very low LCOx. European investment and proximity are key driving factors
Policy Support	1	North Africa's policy support, while improving, is less proven and relies on external demand (e.g. EU offtake tenders)
Feedstocks	7	Raw solar and wind resources are world-class, but infrastructure and investment is a hurdle to using them for large scale new gas exports
Infrastructure	4	North Africa's existing infrastructure for clean fuel exports is limited. Many planned projects are in remote desert/coastal areas requiring new ports, pipelines, and desalination plants. Some LNG, ammonia, and port infra is present
Development	1	Around 34 projects are in planning in North Africa, but all in very early stages

[1] Middle East eyes global role in green hydrogen trade

Readiness to Export – Scoring Framework Results

Brazil and Chile benefit from the lowest green molecule LCOx, and strong international and domestic support

	Brazil	Explanation
Overall Score	4.9	
LCOx	4	Most competitive LCOx for bio-LNG. Despite high hybrid and onshore wind capacity factors, storage costs are high due to uneven profiles
Policy Support	4	Increasingly favourable incentive landscape nationally and regionally, export seen as a priority as maximum percentage law for obtaining tax benefits was removed in 2024. Ranked highest in Latin America on the H2LAC Index 2025[2], but policies are relatively new
Feedstocks	10	World-leading hydro, solar, wind, and biomass resources (2nd largest ethanol producer). Well integrated grid for power delivery
Infrastructure	4	Extensive gas pipeline network and large ports provide a strong base, but does not currently have ammonia and LNG export infrastructure
Development	4	Smallest but growing pipeline H_2 /NH_3 projects (n~44) by region, but not by country. Most in early stages and smaller-scale pilot phase, many MoUs signed but no commercial offtake at scale – FIDs expected 2025 before COP but not achieved

	Chile	Explanation
Overall Score	5.1	
LCOx	10	Second lowest average LCOx across gases particularly for pure wind in the south and pure solar in the north yields the lowest average LCOx
Policy Support	4	Targeted tax breaks and other incentives for green H_2 export, though modest compared to other countries (~$50 M). Streamlining of permits. Stable policy commitment across administrations[2]
Feedstocks	7	Atacama Desert solar capacity factor average is up to 37%, while southern Patagonia onshore wind capacity factors are up to 60%. No useful natural gas or biomass resources
Infrastructure	1	No domestic natural gas or ammonia industry, lacking specific infrastructure for H_2 export (e.g. export terminals, electrolyzer complexes)
Development	4	~75 green H_2/NH_3 projects proposed in Chile mostly early stages of development, no large-scale FIDs. Seven commercially scaled plants currently undergoing EIA. No bio-LNG, e-methane, or blue NH_3 projects planned[3]

[1]H2LAC [2]fDi Intelligence [3]Chile and Green Hydrogen

WP2 – Results Benchmark and Comparative Analysis

H_2 Supply Chain Model Results

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Delivered cost of H_2 to Europe 2030

By 2030, the **cheapest H_2 imports are expected to come from North Africa and the Chile**, driven mainly by low-cost solar and wind resources for Chile, and proximity to Europe for North Africa, saving midstream costs

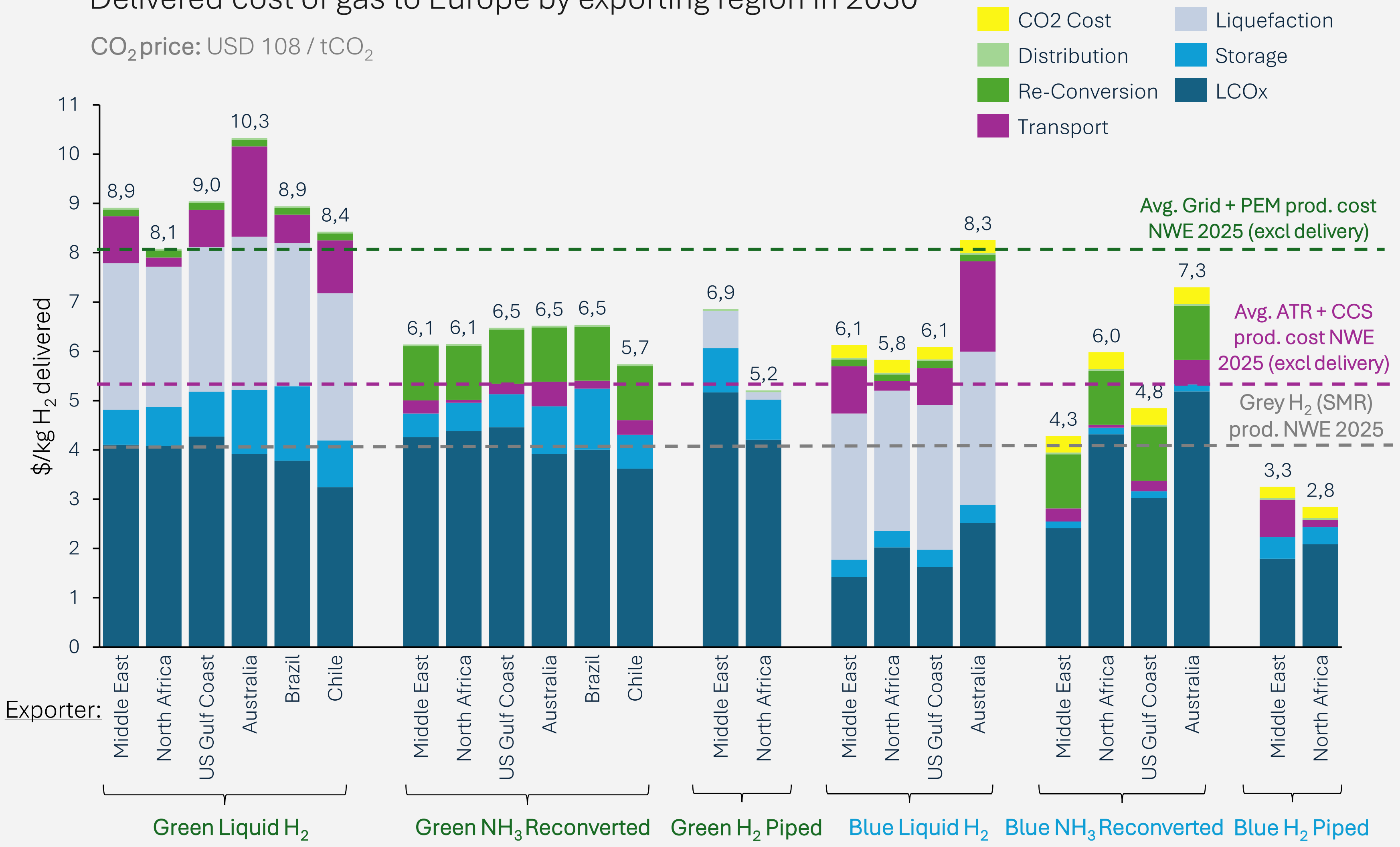
Liquified green H_2 imports are not likely to be competitive with domestic production by 2030. **NH_3 reconverted should be cheaper than domestic green H_2, but not domestic blue or grey H_2 production.** Blue H_2 imports by pipe would be by far the most competitive due to relatively low gas prices abroad, yet no projects are planned

Non-RFNBO value chains are subject to CBAM pricing, adding ~\$0.30-0.50/kgH_2 to imported costs and reflecting Europe's bias for RFNBOs, which could have the same carbon intensity (<70% lifecycle GHG reductions) but can use an electricity emissions factor of zero under CBAM

In 2030, green and blue H_2 by pipeline as well as NH_3 reconverted into H_2 is competitive with domestic production

Delivered cost of gas to Europe by exporting region in 2030

CO_2 price: USD 108 / tCO_2



Optimal hybrid solar and onshore wind are used for all regions, regional specific capacity factors available in associated model. A flat discount rate of 7% is assumed. All cost estimates are without subsidy. Storage costs include H_2 storage during gas production and at the export terminal. Conversion of H_2 to NH_3 is counted in the LCOx bar, re-conversion includes regassification and NH_3 cracking. It is assumed RES based value chains ("green H_2/NH_3") are RFNBO compliant and thus are not subject to CBAM. However, the non RFNBO value chains are subject to CBAM pricing, in this case having zero electricity emissions for production and the value chain, but accounting for the cost of methane emissions and CCS alone under the assumed CO_2 price.

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Delivered cost of H_2 to Europe 2050

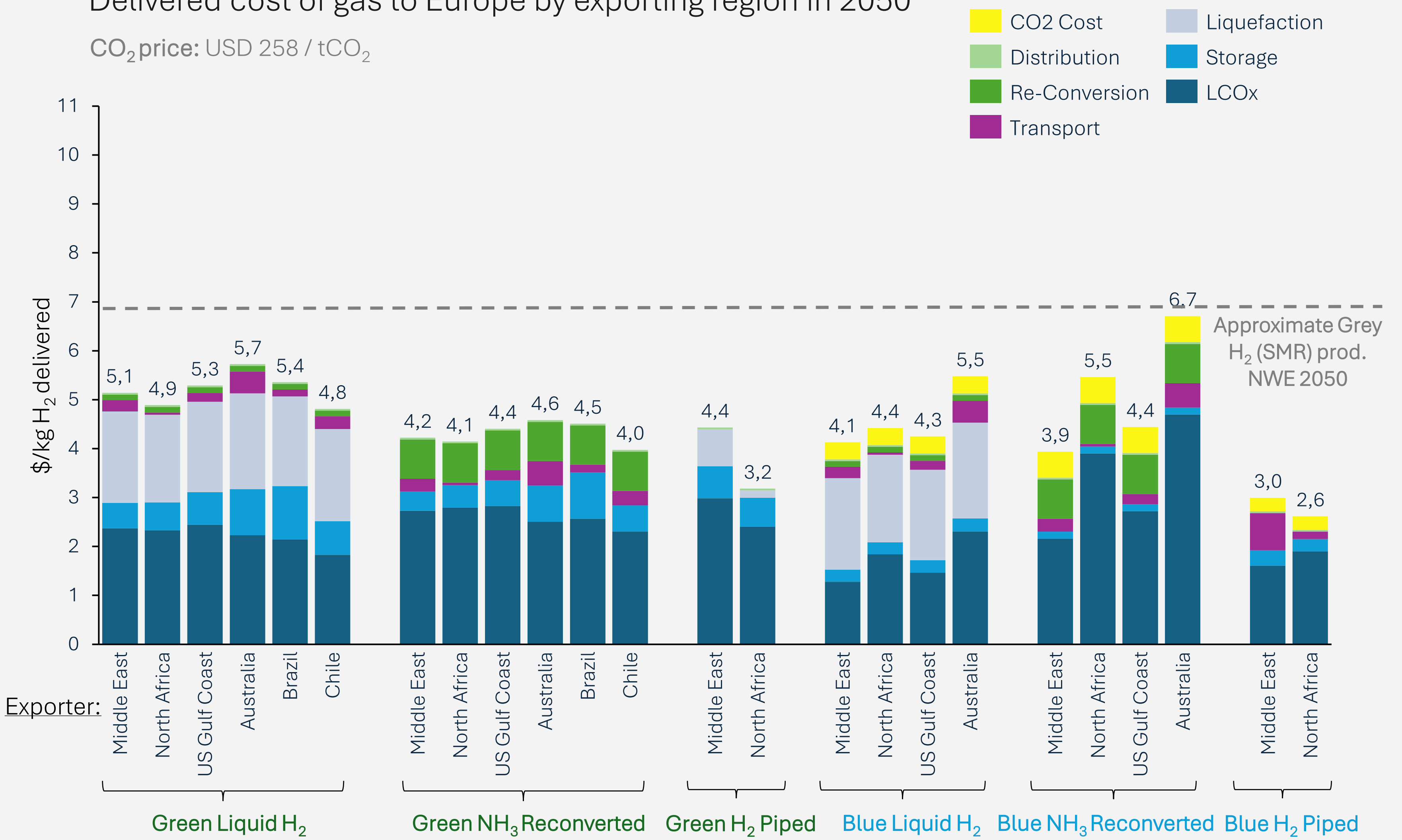
By 2050, **all H_2 imports from the geographies in scope are expected to be less expensive than the average unabated H_2 cost domestically with a high carbon tax.** Still, competitiveness in the various other end-use sectors will depend on their willingness to pay compared to other available options

Renewables-based H_2 is expected to become increasingly competitive with natural gas-based H_2 towards 2050, as conversion, LCOE, and electrolyzer cost reductions are experienced with economies of scale

In 2050, renewables-based and liquefied new gas costs are expected to fall by 30-50% compared to 2030

Delivered cost of gas to Europe by exporting region in 2050

CO_2 price: USD 258 / tCO_2



Optimal hybrid solar and onshore wind are used for all regions, regional specific capacity factors available in associated model. A flat discount rate of 7% is assumed. All cost estimates are without subsidy. Storage costs include H_2 storage during gas production and at the export terminal. Conversion of H_2 to NH_3 is counted in the LCOx bar, re-conversion includes regassification and NH_3 cracking. It is assumed RES based value chains ("green H_2/NH_3") are RFNBO compliant and thus are not subject to CBAM. However, the non RFNBO value chains are subject to CBAM pricing, in this case having zero electricity emissions for production and the value chain, but accounting for the cost of methane emissions and CCS alone under the assumed CO_2 price.

Delivered cost of H_2 to Japan 2030

For Japan, Australia, Chile, and the Middle East are the most competitive suppliers of most H_2 molecules

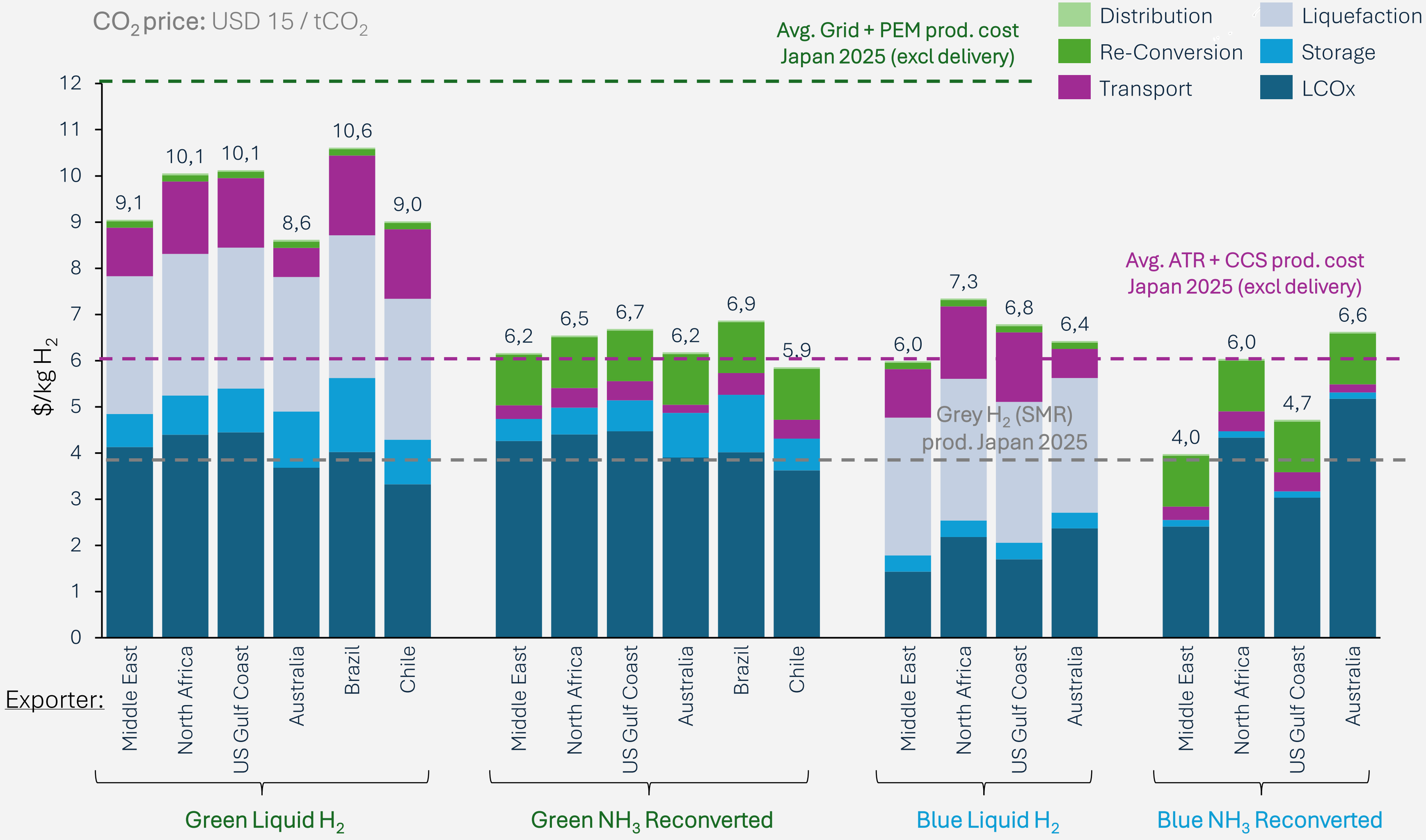
Green and blue NH_3 reconverted into H_2 costs less than green H_2 produced in Japan, **which could catalyze investment into key technological bottlenecks along the supply chain such as NH_3 cracking, and the demand side such as NH_3 co-fired power, green steel production, transport and more.** Despite competitiveness of imports, uptake will come down to willingness to pay and government support

A CBAM equivalent does not currently exist in Japan, so no CO_2 pricing is considered for new gas imports

Similar to Europe, a price premium persists for imported H_2 compared to domestic grey or blue H_2 production

Delivered cost of gas to Japan by exporting region in 2030

CO_2 price: USD 15 / tCO_2



Energy prices, capacity factors, and oversizing dimensions vary by region. Hybrid solar and onshore wind are used for all regions, along with a flat discount rate of 7%, and all cost estimates are without subsidy. Storage costs include H_2 storage during gas production and at the export terminal. Conversion of H_2 to NH_3 is counted in the LCOx bar, re-conversion includes regassification and NH_3 cracking. Regional capacity factor specificity: North Africa: Morocco, Middle East: Saudi Arabia, Brazil: Ceara, Chile: Magallanes, Australia: Pilbara

[1] The view from Japan: 2025

Delivered cost of H_2 to Japan 2050

Similar to Europe, **renewables-based H_2** value chains are expected to be **highly competitive with natural gas-based value chains by 2050**

LCOx accounts for a much smaller portion of the total delivered cost in 2050 compared to the full value chain compared to 2030 for NH_3 especially, as economies of scale drive down production costs

Technological maturity in the H_2 and NH_3 for power sector, green steel making, FCEVs and more will help drive price parity for imported H_2 compared to domestic production, **along with an increasing carbon tax**

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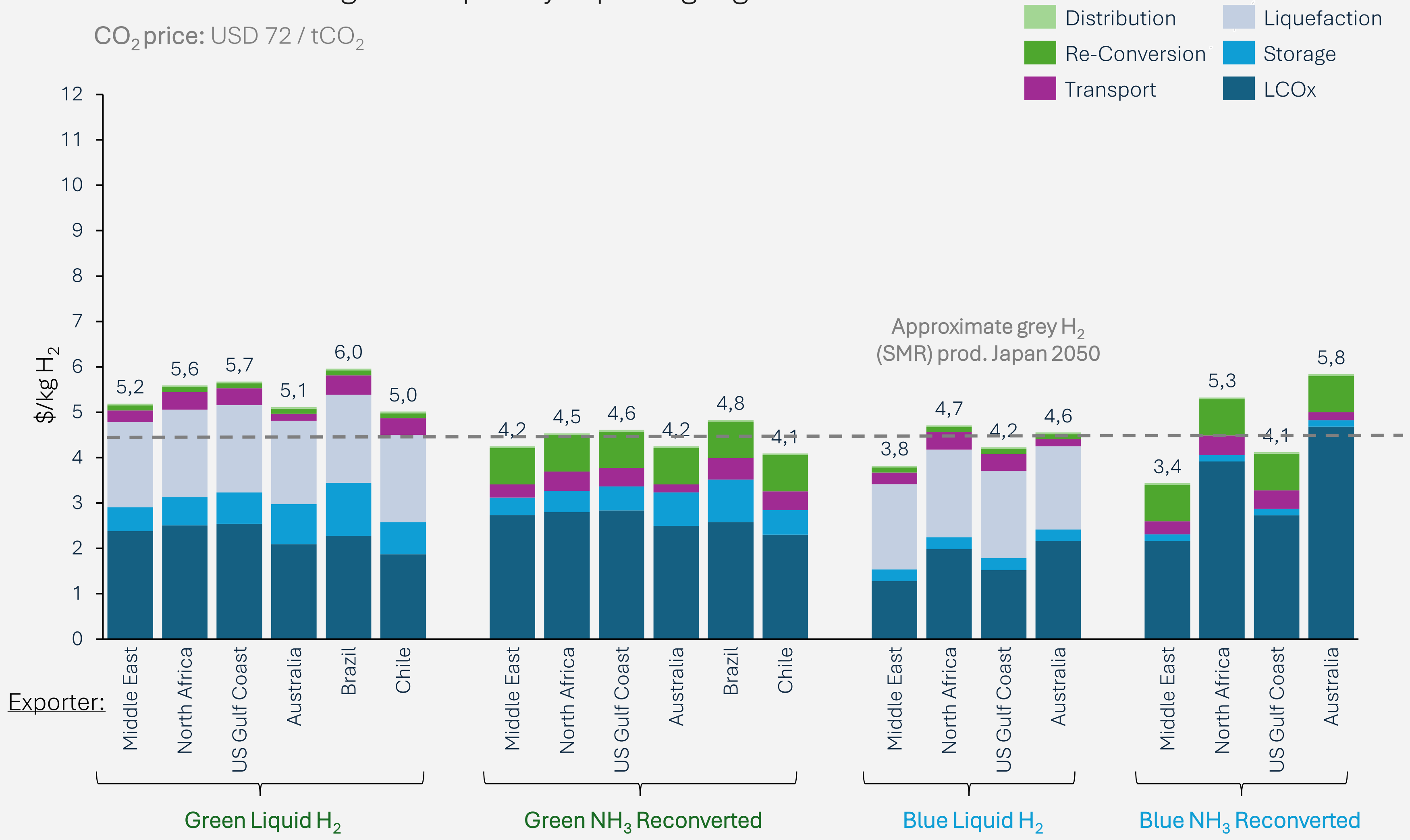
In 2050, a small price premium is expected to persist in Japan for clean H_2 imports

Delivered cost of gas to Japan by exporting region in 2050



Energy prices, capacity factors, and oversizing dimensions vary by region. Hybrid solar and onshore wind are used for all regions, along with a flat discount rate of 7%, and all cost estimates are without subsidy. Storage costs include H_2 storage during gas production and at the export terminal. Conversion of H_2 to NH_3 is counted in the LCOx bar, re-conversion includes regassification and NH_3 cracking. Regional capacity factor specificity: North Africa: Morocco, Middle East: Saudi Arabia, Brazil: Ceara, Chile: Magallanes, Australia: Pilbara

[1] The view from Japan: 2025

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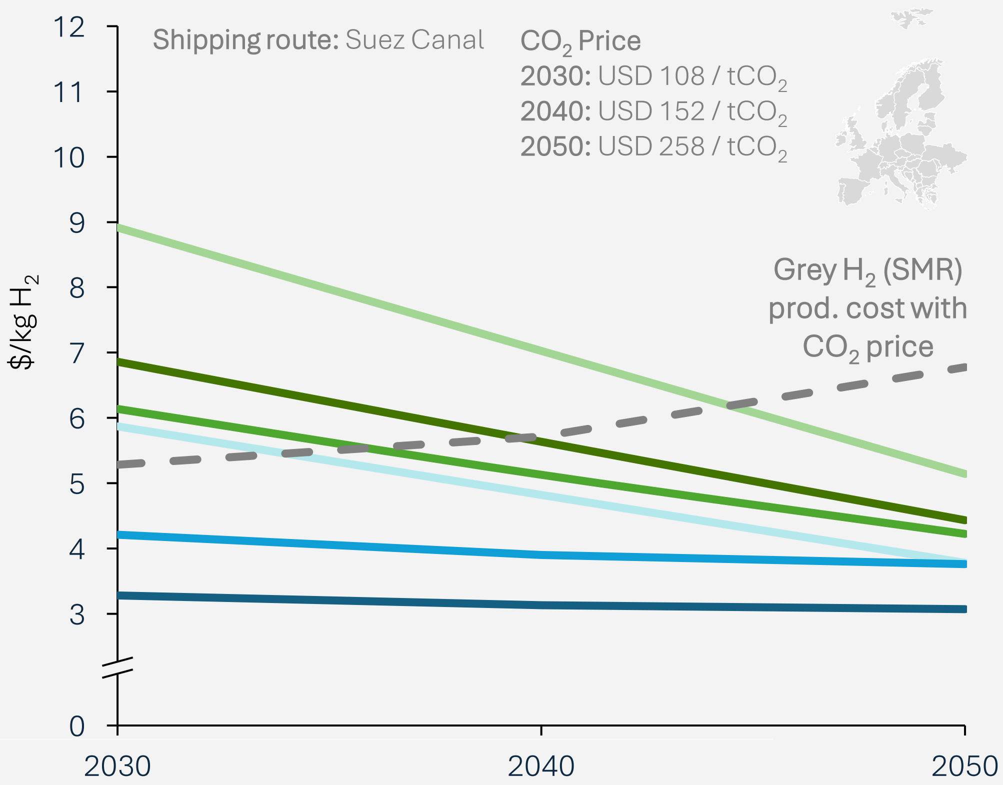
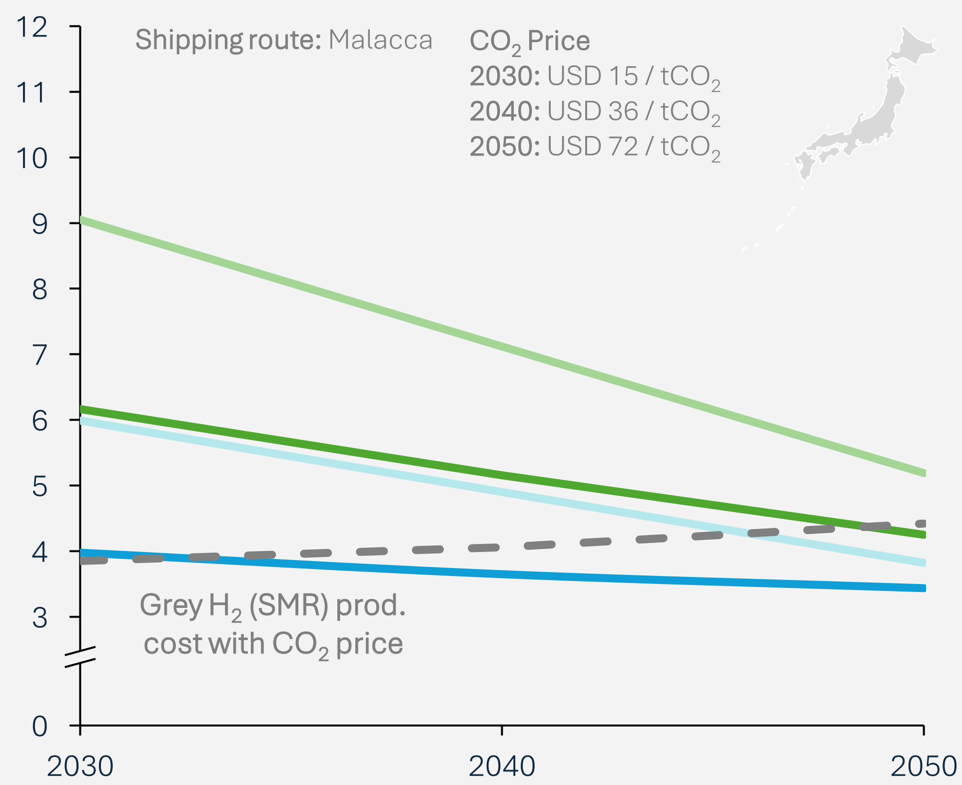
Clean H_2 supply chains are expected to become competitive with local grey H_2 production, and markets will need to adapt to price discovery over time

Large cost reductions are expected for green H_2-based supply chains due to marked improvements in **electrolyzer CAPEX (from ~$1,150/kW in 2030 to ~$750 /kW H_2 in 2050),** efficiency **(from 72% in 2030 to 80% in 2050),** and LCOE reductions **(-35% on average)**. As a result, reductions in OPEX and balancing costs (batteries and on-site H_2 storage) will occur, implying a need to implement flexible H_2 contracting reflecting economies of scale. A high carbon tax penalizes unabated hydrogen production to the extent **that most clean options are more economical in Europe by 2040**, however, the same is not expected to be true in Japan, based on a weaker carbon price outlook, **which could mean support schemes will still be necessary in 2040**, potentially weaning off towards 2050

Delivered cost of H_2 Middle East to Europe by year - $/kg H_2



Delivered cost of H_2 Middle East to Japan by year - $/kg H_2



- Blue H2 liquefied
- Blue H2 as NH3 reconverted
- Blue H2 by Pipeline (EU only)
- Green H2 Liquefied
- Green H2 as NH3 reconverted
- Green H2 by Pipeline (EU only)

Assumptions:

Gas is assumed to be produced in the Saudi Arabia NEOM region using hybrid solar and wind with a total capacity factor of 57% throughout the year. WACC of 7% assumed, subsidies not included

Oversizing of 2.5MW RES to 2MW electrolyzer to 1MW ammonia production assumed

CO_2 cost applied to natural gas-based value chains under CBAM

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CH_4 Supply Chain Model Results

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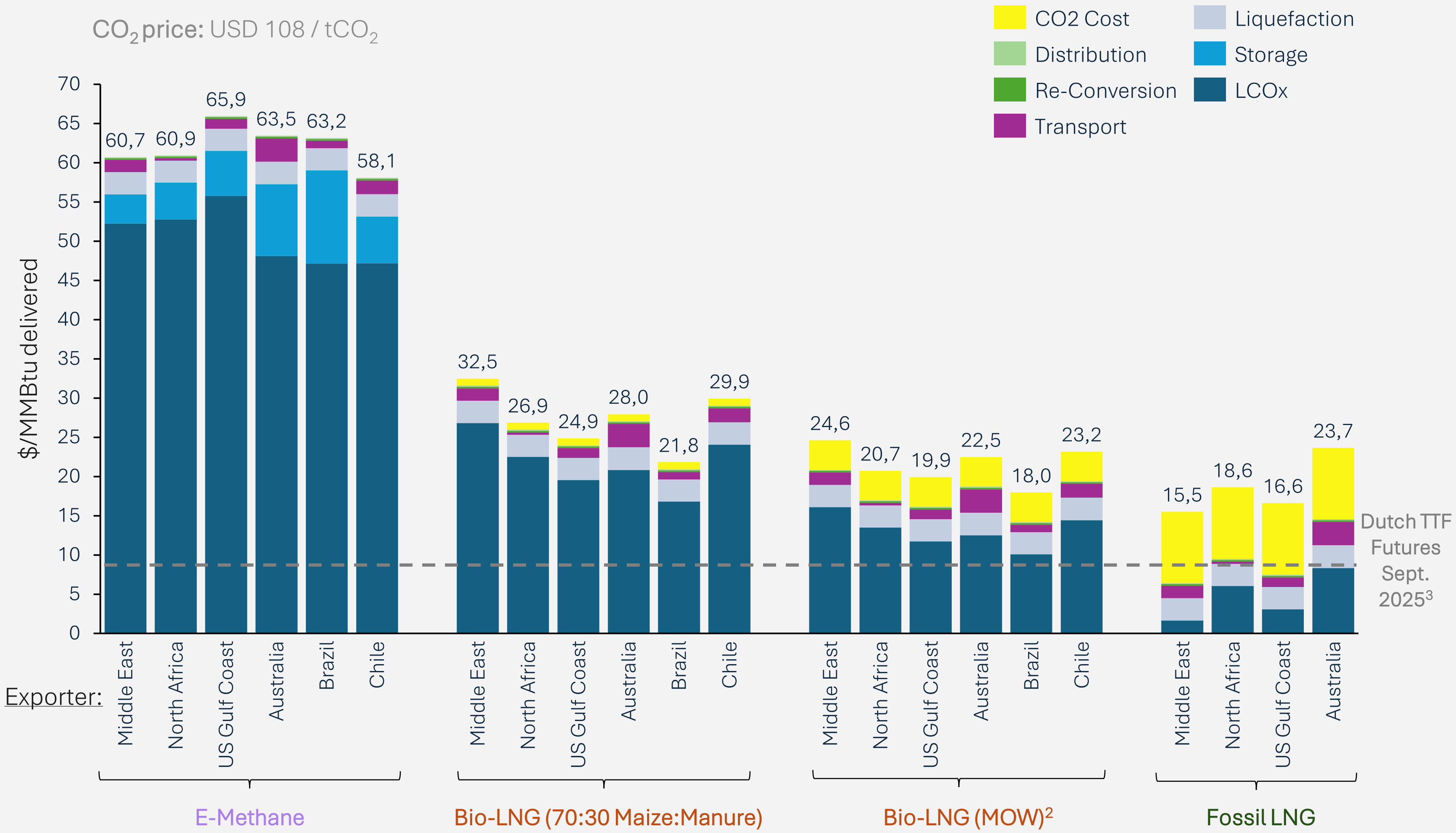
Delivered cost of CH_4 to Europe 2030

In 2030, the price of fossil gas alternatives will be **driven by the EU ETS price and other compliance market policies** such as FuelEU Maritime and REDIII. The transport sector could see the most near-term uptake and highest willingness-to-pay for clean methane, as more compliance mechanisms are in place at the EU and Member State levels to enforce quotas. Bio-LNG is developing within Europe for maritime transport, but imports from abroad are expected to be scarce

Developers are seeking biogenic CO_2 for e-methane production to qualify as RFNBO beyond 2041. Costs be lower in places like the US Gulf Coast and Australia, where ethanol production is high, but CDR (carbon direct removal) markets will compete for low-cost supply, potentially driving the price up

In 2030, e-methane costs are prohibitive at scale in Europe, while low-cost bio-LNG begin to achieve fossil LNG cost parity

Delivered cost of gas to Europe by exporting region in 2030



Energy prices, capacity factors, and oversizing dimensions vary by region. Hybrid solar and onshore wind are used for all regions, along with a flat discount rate of 7%, and all cost estimates are without subsidy. Biogenic CO_2 for e-methane sourced at \$30/tCO_2; representing 3% of total LCOx. [2]Feedstock cost ranges based on the cost curves of manure, MOW, and maize by region Outlook for Biogas and Biomethane [3]Market rate for natural gas in NWE as indexed by the Dutch TTF Natural Gas Futures in September 2025, Dutch TTF Natural Gas Futures Pricing.

Delivered cost of CH_4 to Europe 2050

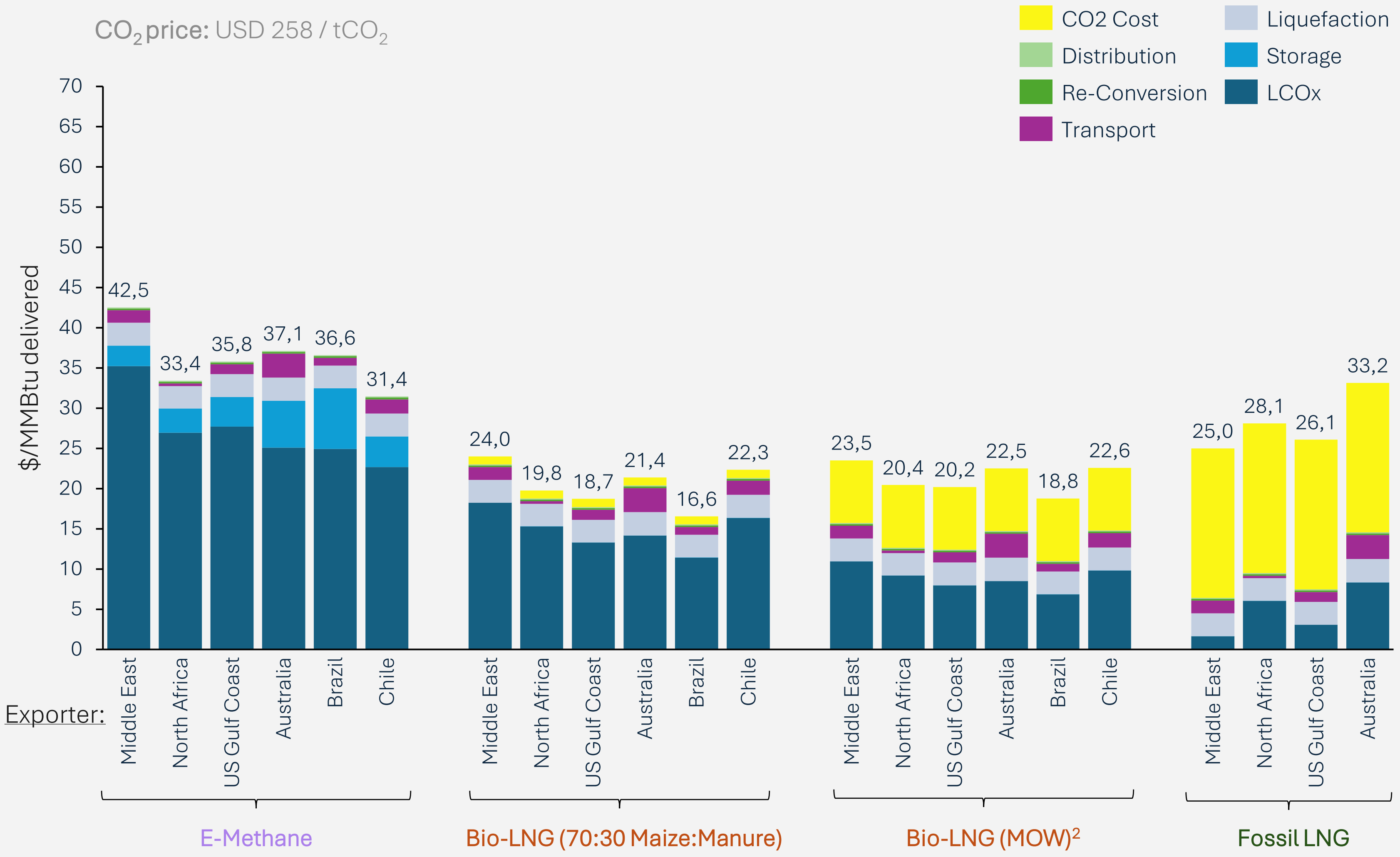
Imported bio-LNG from various sources could be less expensive than fossil LNG in 2050 **when a high carbon price is enforced.** However, volumes from outside of Europe are still expected to be limited as countries will likely use it to **meet their own emissions reduction goals.** Expansion of the EU Interconnected gas grid to places like the US has been talked about, which could facilitate **virtual transfer of the environmental attributes of biomethane without a physical connection**

E-methane is expected to be at least half as expensive in 2050 as in 2030, due to dramatic electrolyzer, methanation plant, and LCOE cost reductions driven by economies of scale. The cost of biogenic CO_2 could, however, increase as low-cost sources (ethanol ~$30/t$CO_2$) get tapped early, and carbon capture at larger-scale facilities such as pulp and paper (~$200/t$CO_2$) becomes more commercially available (adding ~$5/MMBtu to total costs)

Guidehouse analysis 2025

By 2050, e-methane may achieve cost parity with LNG imports in Europe at very high carbon pricing

Delivered cost of gas to Europe by exporting region in 2050



Energy prices, capacity factors, and oversizing dimensions vary by region. Hybrid solar and onshore wind are used for all regions, along with a flat discount rate of 7%, and all cost estimates are without subsidy. Biogenic CO_2 for e-methane sourced at $30/t$CO_2$; representing 3% of total LCOx. [2]Feedstock cost ranges based on the cost curves of manure, MOW, and maize by region Outlook for Biogas and Biomethane

Delivered cost of CH_4 to Japan 2030

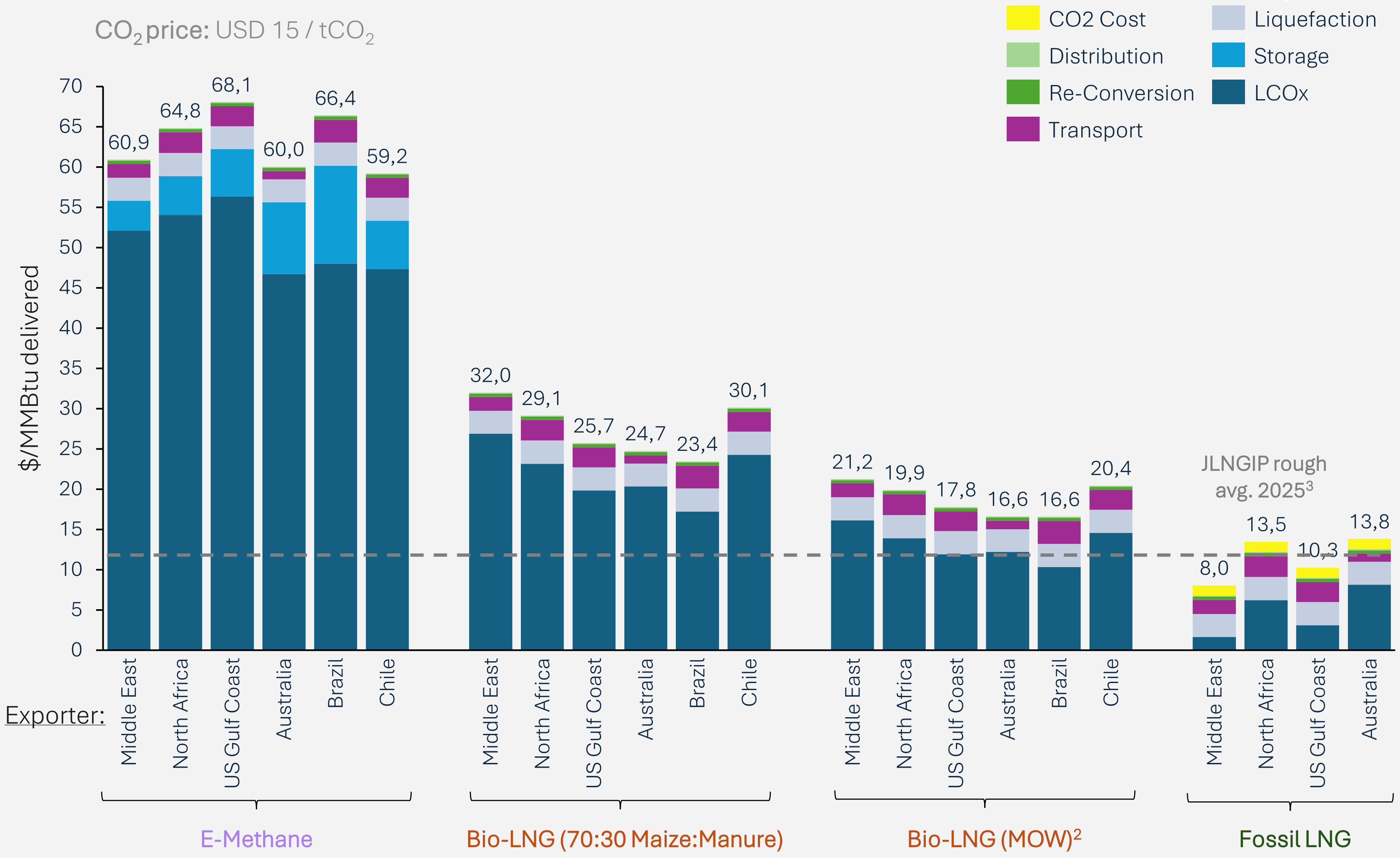
Compared to Europe, Japan is expected to have a much lower carbon price in 2030, creating **less opportunity cost for traditional LNG importers**, resulting in a slightly larger gap in price parity all else considered equal

However, **Japanese gas companies are driving development in the e-methane supply chain globally**. They are striving to inject 1% of gas demand as e-methane by 2030, which could soon be transposed into law as an obligation by METI, supported by necessary financial incentives

CO_2 for e-methane production and export to Japan will likely not be biogenic in 2030, as **Japan currently considers once-recycled CO_2 carbon neutral upon combustion**

In 2030, the lowest-cost e-methane and bio-LNG imports to Japan are likely to come from the US and Australia

Delivered cost of gas to Japan by exporting region in 2030



Energy prices, capacity factors, and oversizing dimensions vary by region. Hybrid solar and onshore wind are used for all regions, along with a flat discount rate of 7%, and all cost estimates are without subsidy. Biogenic CO_2 for e-methane sourced at $20/$tCO_2$ from a gas processing plant, representing ~2% of total LCOx. [2]Feedstock cost ranges based on the cost curves of manure, MOW, and maize by region Outlook for Biogas and Biomethane. [3]Natural gas price from JLNGIP Japan Liquefied Natural Gas Import Price

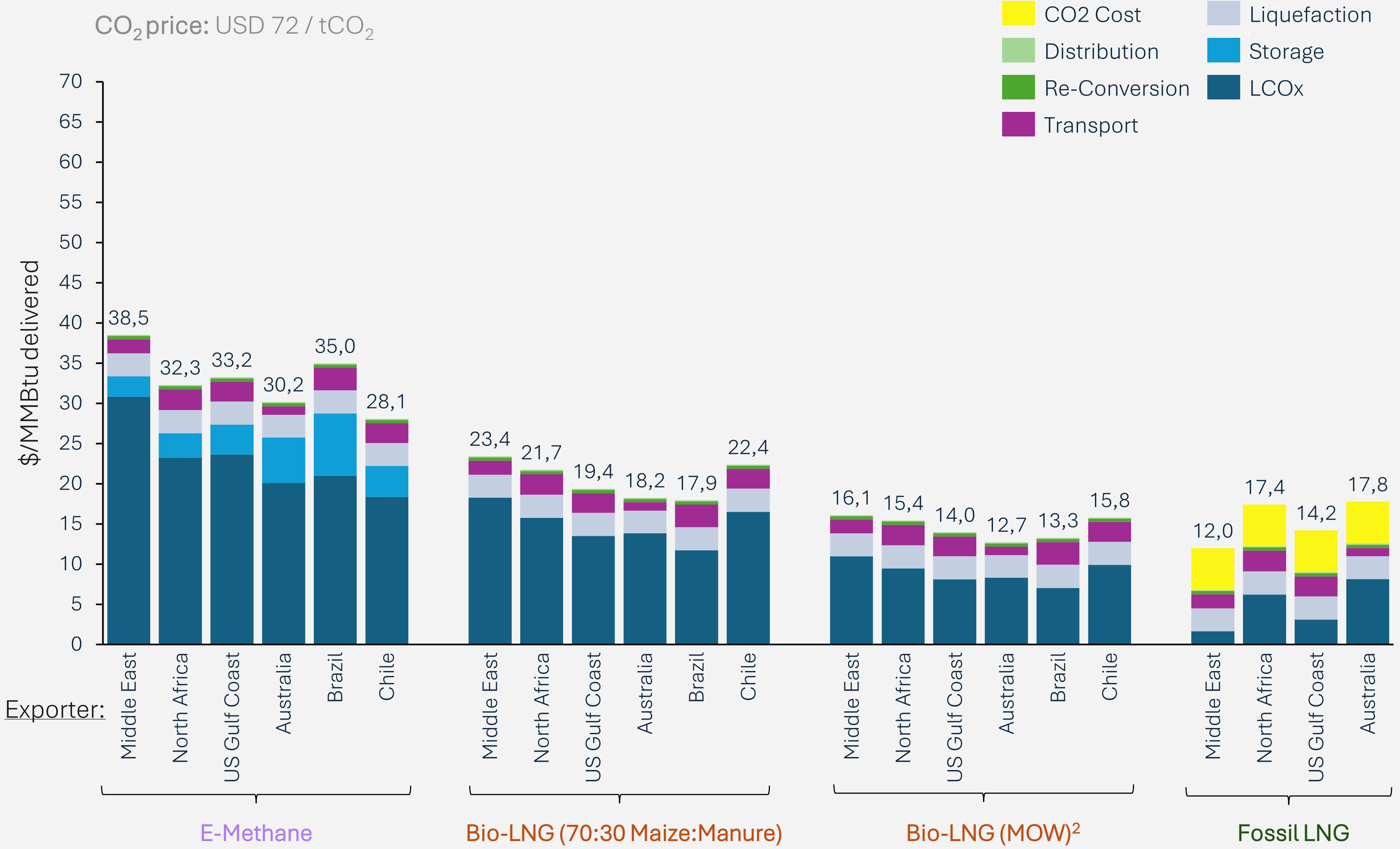
Delivered cost of CH_4 to Japan 2050

Despite a dramatic reduction in cost from 2030 to 2050, the delivered cost of new gases into Japan is likely to remain more expensive than traditional LNG imports by 2050, unless a large jump in carbon price is experienced, cost reductions are more than expected due to technological advances, or other mechanisms are put in place to penalize high-emissions fuels such as compliance quotas. If not, it is likely **some level of subsidization will remain necessary for new gas imports such as e-methane in 2050**

Japan may seek to align further with international regulations surrounding recycled CO_2 accounting for e-methane, requiring developers to use biogenic CO_2 towards mid-century

In 2050, a large price gap could persist between new gases and fossil LNG imports to Japan

Delivered cost of gas to Japan by exporting region in 2050

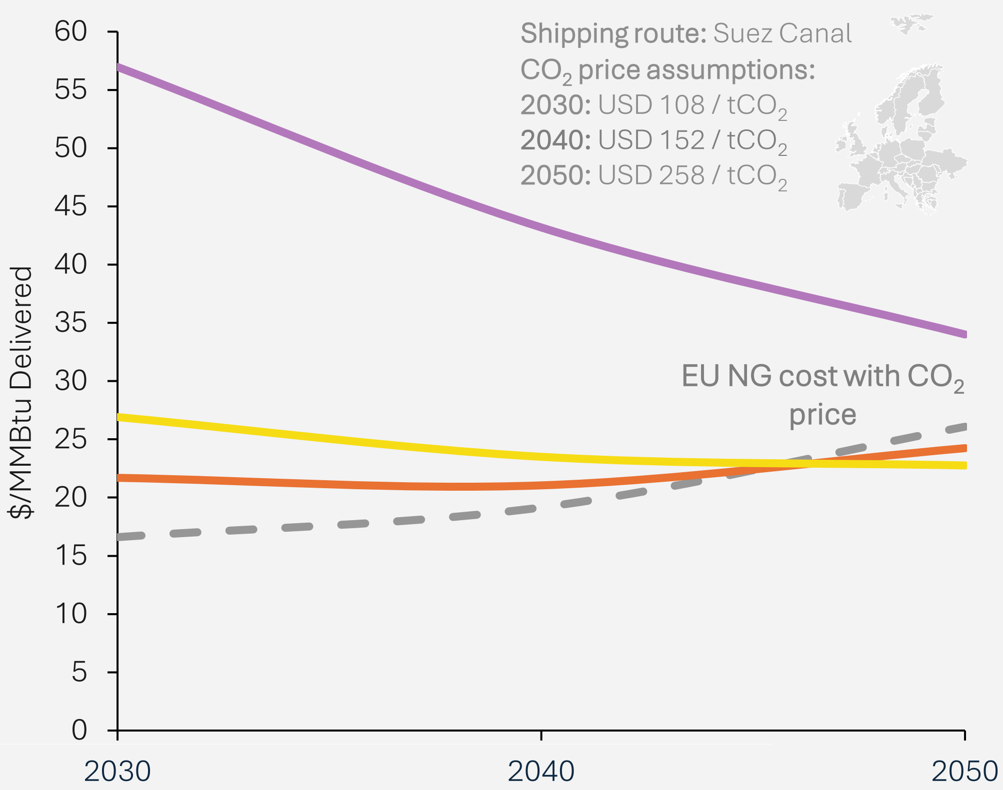


Energy prices, capacity factors, and oversizing dimensions vary by region. Hybrid solar and onshore wind are used for all regions, along with a flat discount rate of 7%, and all cost estimates are without subsidy. Biogenic CO_2 for e-methane sourced at $20/$tCO_2$ from a gas processing plant, representing ~2% of total LCOx. [2]Feedstock cost ranges based on the cost curves of manure, MOW, and maize by region Outlook for Biogas and Biomethane

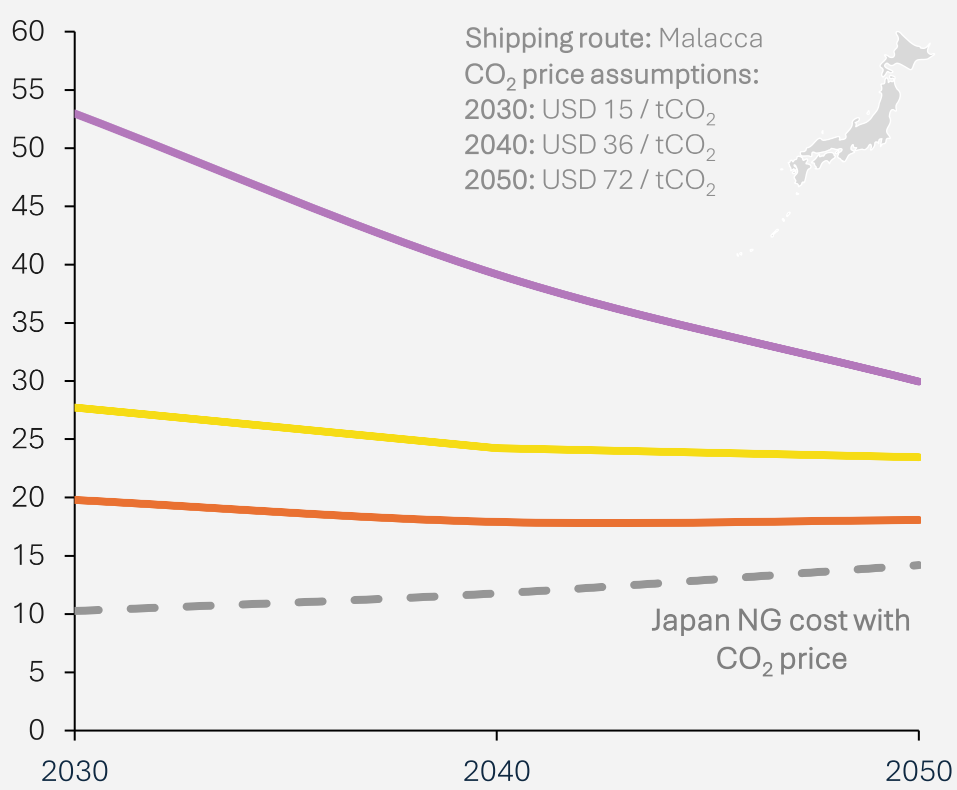
Costs converge towards 2050, opening up markets for decarbonized CH_4, however, economies of scale are needed to drive cost reductions

E-methane and bio-LNG imports into Europe will become increasingly competitive with fossil LNG moving forward as carbon prices increase. **E-methane import costs are expected to decrease by ~40% between 2030 and 2050** due to technological improvements and economies of scale, assuming **electrolysis CAPEX reduces from $1,150/kW in 2030 to $750/kW in 2050**, and **methanation CAPEX from $775/kW in 2030 to $465/kW in 2050.**[1] Japan currently sees a larger role for e-methane in meeting their long-term 90% carbon-neutralized city gas targets for 2050[2], however offtakers in Europe may compete for volumes for e-methane in ETS covered sectors as the cost premium tightens

Delivered cost of CH_4 US Gulf Coast to Europe - $/MMBtu



Delivered cost of CH_4 US Gulf Coast to Japan - $/MMBtu



- E-Methane: Dedicated RES and PPAs
- Bio-LNG: Municipal organic waste
- Bio-LNG: Wet manure + maize (70-30)

Assumptions:

Energy prices, capacity factors, and oversizing dimensions vary by region. Hybrid solar and onshore wind are used for all regions, along with a flat discount rate of 7%, and all cost estimates are without subsidy

Biogenic CO_2 for e-methane exported to Japan sourced at $20/$tCO_2$ from a gas processing plant, while exports to the US are assumed to be using biogenic CO_2 from a pulp and paper plant at $200/$tCO_2$, **leading to a 16% increase in LCOx**

Feedstock cost ranges based on the cost curves of manure, MOW, and maize by region IEA

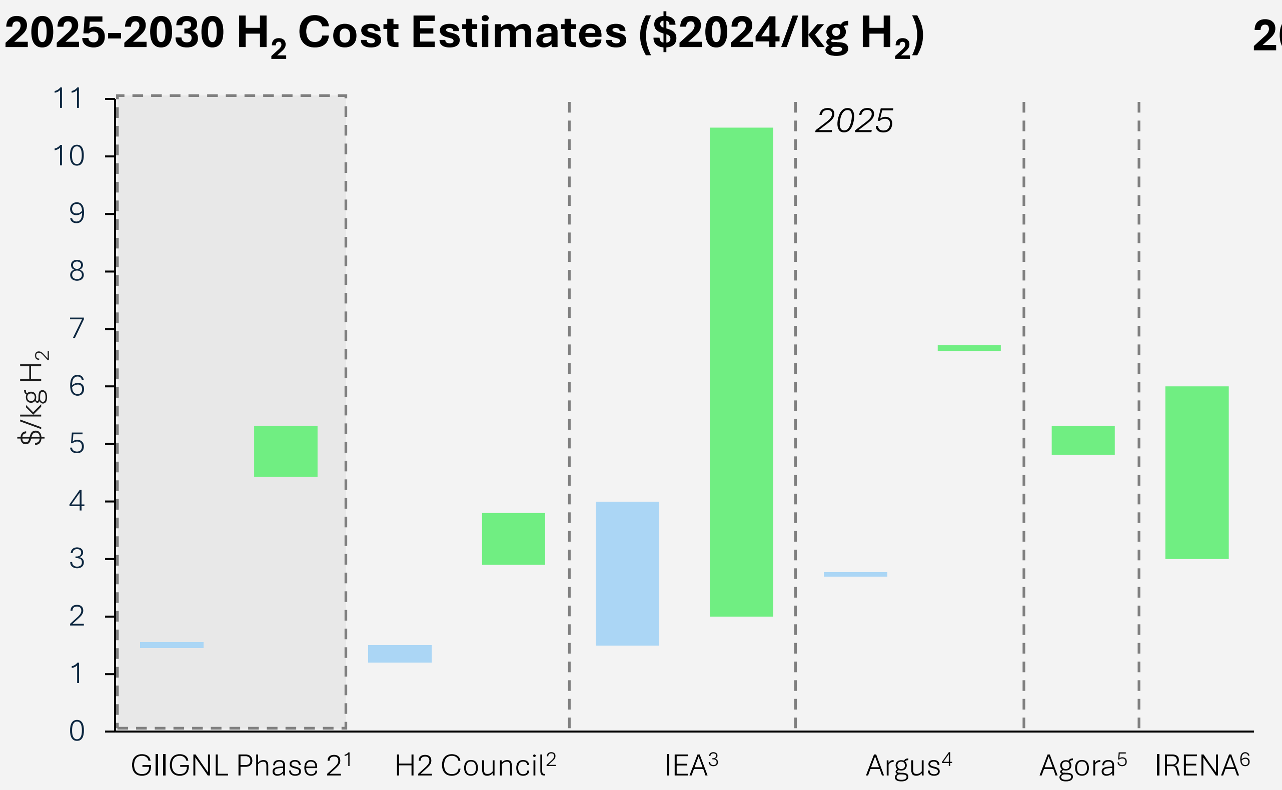
[1] juser.fz-juelich.de

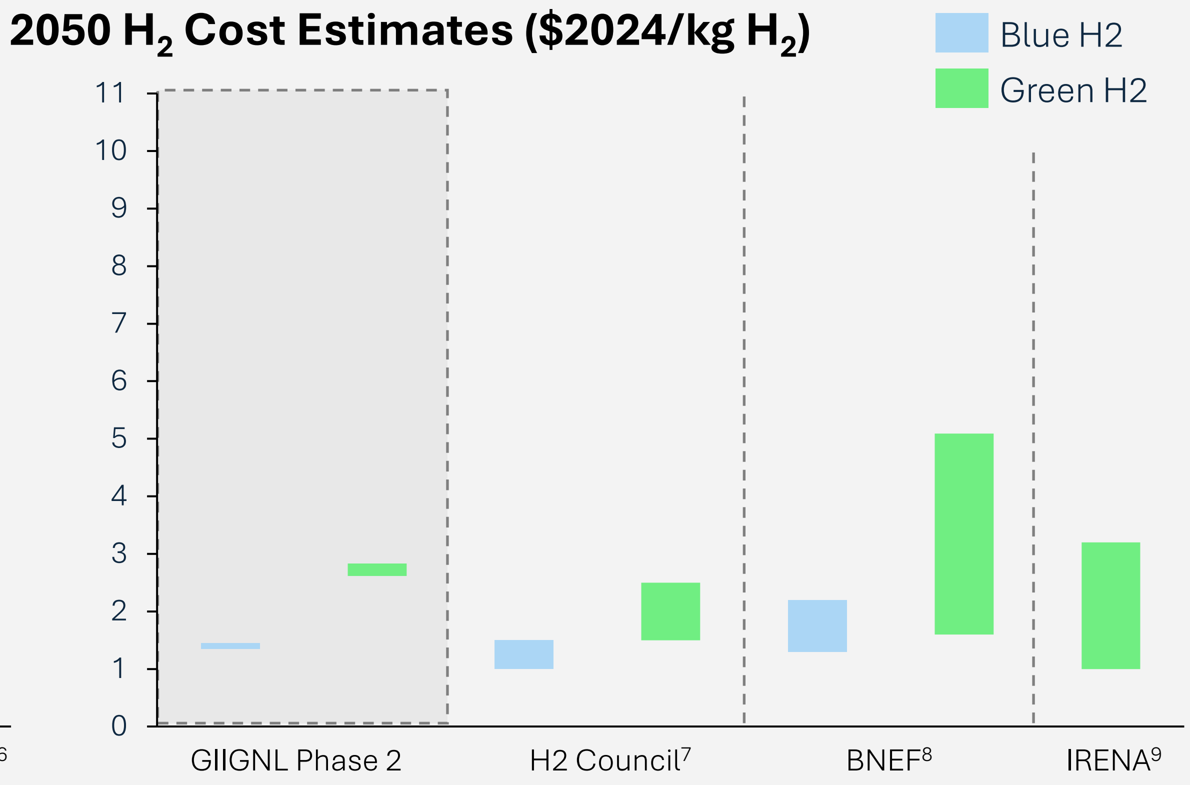
[2] カーボンニュートラル チャレンジ

Assumptions and Results Benchmark

Levelized Cost of H_2 Production Across Reports

Reported H_2 costs have changed over the previous years, with the **near-term cost expectation for green H_2 increasing 30-65% since 2022**, stemming from increased cost of capital particularly straining capital-intensive renewable projects, interrupted supply chains, skilled labor shortages, and strain on global trade.[7] Additionally, **organizations are increasingly weary of reporting costs beyond 2030**, with the H2 Council having taken down their "*Green Hydrogen Cost Reduction: Scaling up electrolyzers to Meet the 1.5 °C Goal* (2020)" report. The GIIGNL Phase 2 study falls within the **middle bounds** of the studies captured below





[1]Upper and lower bound based on RES cost range assumption in the model, produced in USGC. [2]2025 estimate of production in the USGC including incentives Hydrogen Insights 2025 [3]Range of LCOH produced from solar PV, in which the onshore wind costs fall within. Vast differences come from variations in geography affecting all input cost aspects IEA 2024 [4]Reported costs of USGC production in 2025 from diurnal RES, range corresponding to spread between May and April 2025. Green H_2 from PEM and Blue NH_3 is ATR+CCS based. Elz capacity factor 80% Argus Sample H2 [5]85% PV, 15% onshore wind power WEB.pdf [6]IRENA 2024 [7]Based on survey of member FEED studies H2 Council [8]BNEF [9]Range corresponding to LCOE of $20/MWh and $65/MWh IRENA

Detailed H_2 Assumptions

Not Available	Assumed Value
-	

The largest variation in outlook of electrolyzer cost assumptions is in CAPEX, with recent views being far more conservative

Report	Assumption	2030	2040	2050
GIIGNL[1]	CAPEX ($kWe)	1,150	950	750
H2 Council[2]	CAPEX ($kWe)	1,200-1,500	850-1,020	765-1,020
IEA	CAPEX ($kWe)	960	-	-
Argus[3]	CAPEX ($kWe)	2,200 (2025)	-	-
Agora[4]	CAPEX ($kWe)	887	-	-
IRENA[5]	CAPEX ($kWe)	650-1,000	-	130-307
GIIGNL	OPEX (%)	3	3	3
H2 Council	OPEX (%)	-	-	-
IEA	OPEX (%)	3	-	-
Argus	OPEX (%)	3.5 (2025)	-	-
Agora	OPEX (%)	4	-	-
IRENA	OPEX (%)	-	-	-
GIIGNL	Elz efficiency (%)	72	75	80
H2 Council	Elz efficiency (%)	-	-	-
IEA	Elz efficiency (%)	69	-	74
Argus	Elz efficiency (%)	-	-	-
Agora	Elz efficiency (%)	67	-	-

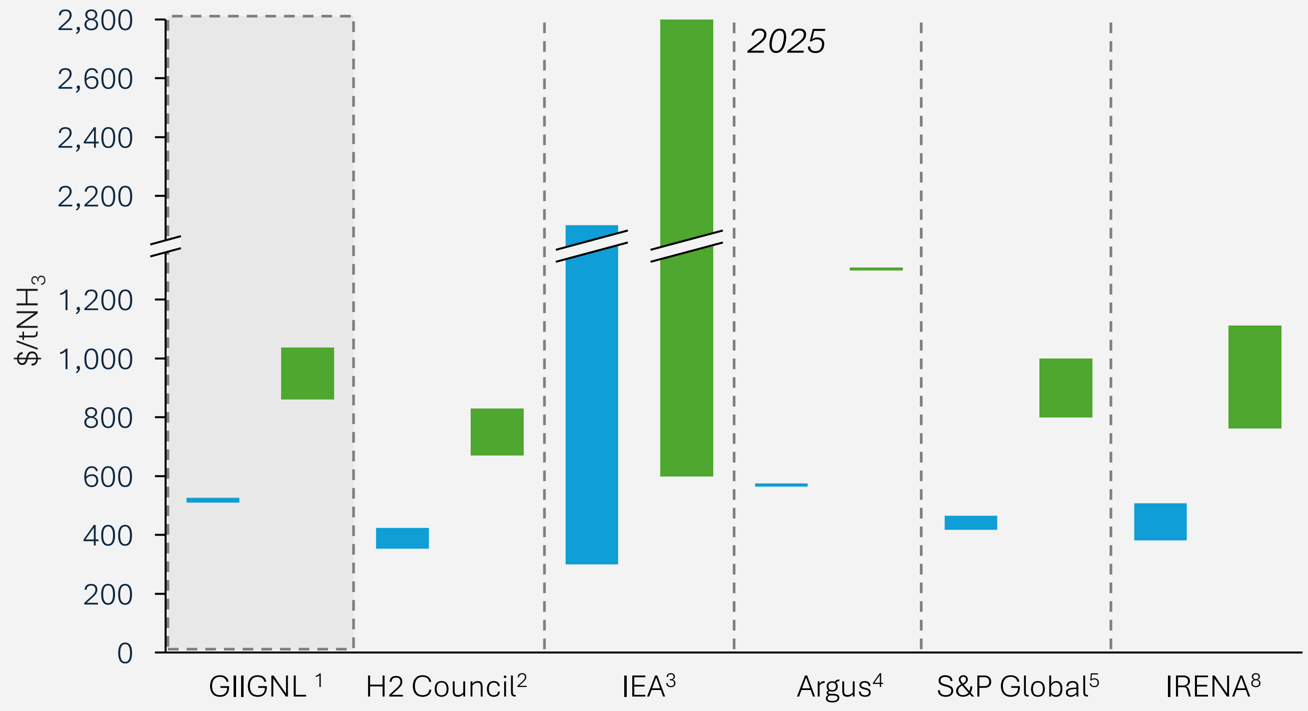
Report	Assumption	2030	2040	2050
GIIGNL	LCOE ($/MWh)	29-44	24-29	20-25
H2 Council	LCOE ($/MWh)	35-50	35-50	35-50
IEA	LCOE ($/MWh)	14-90	-	-
Argus	LCOE ($/MWh)	54 (2025)	-	-
Agora	LCOE ($/MWh)	80	-	-
IRENA	LCOE ($/MWh)	20-65	20-65	20-65
GIIGNL	Gas ($/MMBtu)	3	3	3
H2 Council	Gas ($/MMBtu)	4.4	4.4	4.4
IEA	Gas ($/MMBtu)	1-15	-	-
Argus	Gas ($/MMBtu)	-	-	-

All values reported in USD 2024. [1]CAPEX trajectory based on McKinsey & H2Council updated outlook using member FEED studies Hydrogen Insights, and TNO learning curve assessment assuming global capacity reaches 1TW by 2050 TNO. Lower and upper bound of hybrid solar and wind in the USGC. [2]CAPEX values based on survey of member FEED studies, 2040 and 2050 values assume 15% reduction in costs for large scale systems (1GW). Lower bound wind, upper bound solar in the USGC. They do not have published assumptions around efficiency or OPEX, but predict both will decline over time. [3]Argus assumptions are all for 2025. [4]Calculated using total CAPEX, efficiency, and plant size SNG_Imports_WEB.pdf [5]IRENA cost prediction from 2020 report on green hydrogen cost reduction, taken down since its publication, representative of the 2050 costs only in the previous slide, where the 2030 numbers are only a reported range without disclosure of assumptions

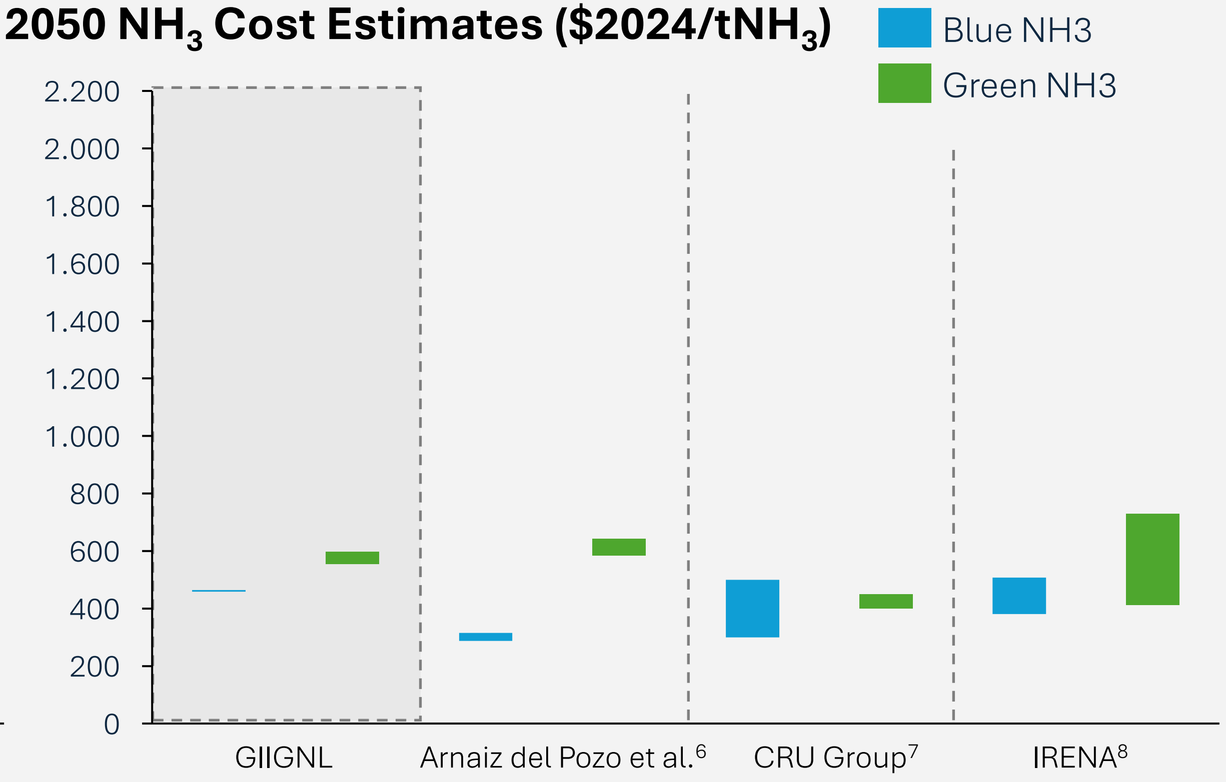
Levelized Cost of NH_3 Production Across Reports

The reported costs of NH_3 is equally as variable as pure H_2, with the GIIGNL Phase 2 model landing in the **middle range** as well. Outside of modeled costs, recent NH_3 auctions are providing some price discovery, such as the H2Global **~\$935/tNH_3 (€811) auction for green NH_3 production in Egypt**, and the recent auctions run by SECI in India with initially auction winners coming in between **\$590/tNH_3 and \$641/tNH_3**. Critically, the Egyptian NH_3 price is unsubsidized and meets hourly correlation requirements for RFNBO status, while the Indian NH_3 prices factor in \$85-106/tNH_3 subsidies for the first three years and are taking 12-month grid averages via “grid-banking” allowing them to operate electrolyzer at near baseload, thus reducing capital expenditures on new RES[9]

2025-2030 NH_3 Cost Estimates (\$2024/tNH_3)



2050 NH_3 Cost Estimates (\$2024/tNH_3)



[1]Upper and lower bound based on renewable energy cost range in the model, produced in USGC. [2]2025 estimate of production in the USGC Hydrogen Insights 2025 [3]Range of LCOA from renewable energy IEA 2024 [4]Reported costs of USGC production in 2025 from diurnal RES, range corresponding to spread between May and April 2025. Green H_2 from PEM and Blue NH_3 is ATR+CCS based. Argus Sample H2. [5]Indicative values of offers from the USGC between 2023 and 2025 for green NH_3 S&P Global and range of previous three months blue NH_3 USGC pricing S&P Global [6]ScienceDirect [7]CRU Group [8]IRENA 2021 [9]Renewable ammonia price discoveries: a closer look at the H2Global and SECI auctions

Detailed NH_3 Assumptions

Not Available	Assumed Value
-	

Although detailed assumptions are scarce, the grouping of assumptions is much tighter for ammonia related costs

Report	Assumption[1]	2030	2040	2050
GIIGNL[2]	CAPEX ($/tNH3)	727-857	727-857	727-857
H2 Council[3]	CAPEX ($/tNH3)	-	-	-
IEA[4]	CAPEX ($/tNH3)	770	770	770
Argus[5]	CAPEX ($/tNH3)	529-772 ('25)	-	-
S&P[6]	CAPEX ($/tNH3)	-	-	-
Arnaiz et al.[7]	CAPEX ($/tNH3)	-	-	615
IRENA[8]	CAPEX ($/tNH3)	-	-	-
GIIGNL	OPEX (%)	3	3	3
H2 Council	OPEX (%)	-	-	-
IEA	OPEX (%)	3	3	3
Argus	OPEX (%)	-	-	-
S&P	OPEX (%)	-	-	-
Arnaiz et al.	OPEX (%)	-	-	3
IRENA	OPEX (%)	-	-	-
GIIGNL	Load Factor (%)	91	91	91
H2 Council	Load Factor (%)	95	-	-

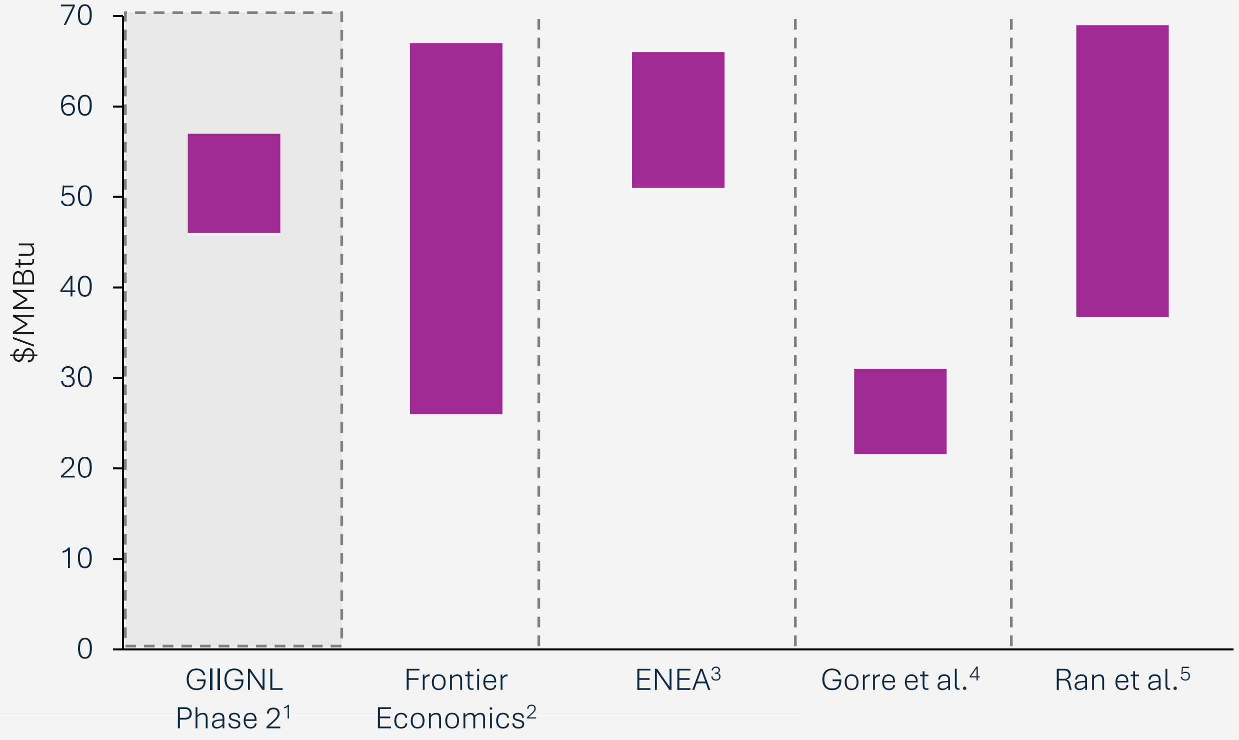
Report	Assumption	2030	2040	2050
IEA	Load Factor (%)	95	-	-
Argus	Load Factor (%)	90 ('25)	-	-
S&P	Load Factor (%)	-	-	-
Arnaiz et al.	Load Factor (%)	-	-	85
IRENA	Load Factor (%)	-	-	-
GIIGNL	Efficiency (%)	89	91	92
H2 Council	Efficiency (%)	-	-	-
IEA	Efficiency (%)	88	88	88
Argus	Efficiency (%)	-	-	-
S&P	Efficiency (%)	-	-	-
Arnaiz et al.	Efficiency (%)	-	-	87
IRENA	Efficiency (%)	-	-	-

[1]For the Haber Bosch process only. All values reported in USD 2024. [2]Low bound for blue NH_3 production only, upper bound includes an extra air separation unit necessary for green NH_3 production.[3]H2Council had not disclosed most of their assumptions. [4]Cost assumptions from assumptions Annex 2024, old annex versions assume costs remain static until 2050 IEA [5]Assumptions for sample data 2025 costs, lower bound corresponding to ATR+CCS based NH_3 production and upper corresponding to PEM based NH3 production, high bounds. Assumptions [6]S&P only reporting commodity prices, not detailing underlying assumptions. [7]For the green NH_3 synthesis loop alone [8]Not disclosed

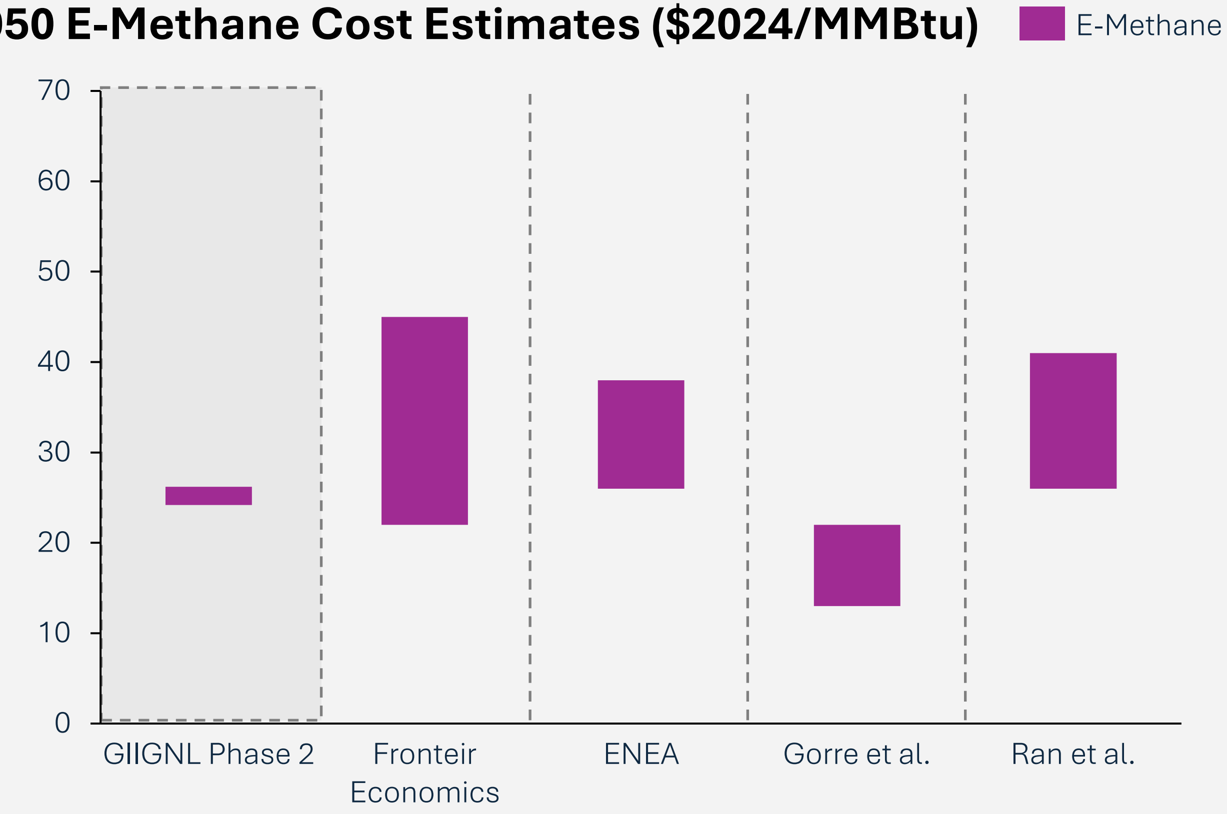
Levelized Cost of E-Methane Production Across Reports

E-Methane costs estimates vary depending on a host of factors, largely due to variable assumptions on hours of operation, electrolyzer and methanation CAPEX evolution, assumed electricity costs, CO_2 source, location and storage costs etc. This is potentially the reason for the lack of reported values by larger international organizations, who have not released many reports on the cost evolution of e-methane. **The present study uses a statistical amalgamation of CAPEX and OPEX values to assume the most likely trajectory of costs,**[6] and is **middle of the pack** in terms of levelized cost results

2030 E-Methane Cost Estimates ($2024/MMBtu)



2050 E-Methane Cost Estimates ($2024/MMBtu)



[1]Costs based on production using hybrid solar and onshore wind in Saudi Arabia, with CO_2 coming from a gas processing plant. Lower and upper bound correspond to LCOE scenarios. [2]Costs from Frontier Economics PtX model, reported in 2021 Delft study, range mainly attributed to different CAPEX assumptions and electricity costs; CO_2 from cement plant Delft 2021. [3]Range attributed to different electricity costs ENEA [4]Range attributed to 10 and 25 euro/MWh electricity price Gorre et al. [5]Ran et al. 2025 lower bound production in China upper bound in Japan Ran et al. [6]juser.fz-juelich.de

Detailed E-Methane Assumptions

Not Available	Assumed Value
-	

CAPEX assumptions are highly variable, likely as most come from scientific studies rather than real projects

Report	Assumption[1]	2030	2040	2050
GIIGNL[2]	CAPEX ($/kW$_{CH4}$)	761	568	456
Frontier[3]	CAPEX ($/kW$_{CH4}$)	828	-	633
ENEA[4]	CAPEX ($/kW$_{CH4}$)	1000	-	700
Gorre et al.[5]	CAPEX ($/kW$_{CH4}$)	475	-	297
Ran et al.[6]	CAPEX ($/kW$_{CH4}$)	-	-	-
GIIGNL	OPEX (%)	4	4	4
Frontier	OPEX (%)	3	3	3
ENEA	OPEX (%)	5	5	5
Gorre et al.	OPEX (%)	5	-	3
Ran et al.	OPEX (%)	3	3	3
GIIGNL	Efficiency (%)	72	79	85
Frontier	Efficiency (%)	80	80	80
ENEA	Efficiency (%)	79	79	79
Gorre et al.	Efficiency (%)	75	-	78
Ran et al.	Efficiency (%)	75	75	75

Report	Assumption	2030	2040	2050
GIIGNL	Load Factor (%)	75	75	75
Frontier	Load Factor (%)	91	91	91
ENEA	Load Factor (%)	89	-	69
Gorre et al.	Load Factor (%)	97	97	97
Ran et al.	Load Factor (%)	91	91	91
GIIGNL	LCOE ($/MWh)	30	26	22
Frontier	LCOE ($/MWh)	46	-	36
ENEA	LCOE ($/MWh)	60	-	15
Gorre et al.	LCOE ($/MWh)	25	25	25
Ran et al.	LCOE ($/MWh)	98	98	98

[1]For the Methanation process only. All values reported in USD 2024. [2]Values taken as the middle ground of an in-depth benchmark of values juser.fz-juelich.de [3]Reference CAPEX taken, yet the full cost range includes higher and lower values tested in the Frontier model. Other Fronteir values are also variable, reference values chosen. PtG/PtL Calculator. No size specified [4]5 MW $_{HHV\ SNG}$ system, oversizing 2:1 electrolyser to methanation ENEA[5] Most economic assumptions based on project experience from STORE&GO and other PtG projects where the authors are involved. Oversizing of 10 MW of electrolyser capacity and 4.10 MW of methanation assumed Gorre et al. [6]CAPEX assumptions not specified here, as they are not one-to-one, since they only include the methanation island and cost adders for other components Ran et al

Detailed Description of Phase 2 Updates (1/3)

Update	Rationale	Effect
Presentation of hydrogen and methane molecule value chain costs are split and compared to fossil counterparts, such as traditional SMR (or grey) hydrogen production costs and emissions, and local fossil natural gas prices	This is done to have a more apples-to-apples comparison of the cost premium for specific molecules, although this will be dictated more by the willingness to pay by end-use sector	Comparing clean hydrogen value chain costs to fossil hydrogen shows increased competitiveness versus comparison of clean hydrogen to natural gas
Increase in cost of unabated fossil hydrogen and natural gas benchmarks due to increasing carbon price in Europe and Japan was modeled in Phase 2	Done to better account for the real opportunity cost of new gases with an increasing carbon price	Increase in competitiveness for new gases by 2040 and 2050 especially in Europe where parity is reached for many new gases
Electrolysis CAPEX assumptions adjusted from • \$814/kWe 2030, \$589/kWe 2040, and \$447/kWe 2050 to • \$1,150/kWe 2030, \$950/kWe, and \$750/kWe 2050	Aligning with Hydrogen Council and McKinsey's near-term outlook on large-scale electrolysis systems (1GW) and recent data on cost increases of 30-65%. Forecasted outlook for 2040 and 2050 based on TNO learning curve assessment, assuming global capacity reaches 1TW by 2050 conservatively	Across all of these updates to RES-based value chains (green hydrogen, green ammonia, and e-methane): • An average cost reduction of LCOx for green ammonia and e-methane of 40% in 2030 and 25% in 2050 compared to Phase 1 • 25% in 2030 and 5% in 2050 for liquefied and piped green hydrogen compared to Phase 1
E-methane CAPEX assumptions increased from • $\$440/\text{kW}_{SNG}$ 2030, $\$320/\text{kW}_{SNG}$ 2040, and $\$280/\text{kW}_{SNG}$ 2050 to • $\$761/\text{kW}_{SNG}$ 2030, $\$568/\text{kW}_{SNG}$ 2040, and $\$456/\text{kW}_{SNG}$ 2050	Aligning with results on WP3 benchmark, choosing values from a large benchmark of many studies: juser.fz	
Region-specific capacity factors for solar, onshore wind and hybrid solar and onshore wind were made in phase 2, along with **region-specific oversizing ratios**	Done to increase the regional specificity of costs, compared to Phase 1, which used solar in the Middle East as a production profile proxy for all regions	
O&M as a percentage of CAPEX assumptions updated from • 5% to 3% for green hydrogen • 4.7% to 3% for green ammonia • 5% to 3% for e-methane	Done to align with WP3 benchmark results, which are on average lower than Phase 1 estimates	

Detailed Description of Phase 2 Updates (2/3)

Update	Rationale	Effect
• **Input CO_2 costs for Japan** assumed to be non-biogenic, sourced from a gas processing plant at \$20/tCO_2 • **Input CO_2 costs for Europe** assumed to be biogenic, sourced from a pulp and paper mill at \$200/tCO_2	This is done to reflect the impact of Europe's more stringent regulatory framework on e-methane LCOx	Increase in LCOx of e-methane destined for Europe of ~16% under these assumptions
Different biomethane feedstocks (MOW, animal manure, 70:30 manure and maize) with corresponding costs and carbon intensities added to model	Done to compare costs and CI admissibility of various bio-LNG types	Cost and CI depend on feedstock
• **USGC natural gas cost** updated from \$5.4/MMBtu to 3/MMBtu • **North Africa natural gas cost** updated from \$3/MMBtu to \$6/MMBtu	• USGC based on 2024 and 2025 pricing rough average Henry Hub Natural Gas Spot Price • North Africa based on an average of Egypt and Algeria	This results in larger value chain cost decreases for natural gas-based value chains (for example from 4% to 10% for blue ammonia between 2030 and 2050) between 2030 and future timeframes compared to Phase 1
No increase in gas pricing over time was modeled in Phase 2 as was the case in Phase 1	Too difficult to assume the future gas price on a decade timeframe	
Specific hydrogen storage costs for ammonia and e-methane production based on region-specific RES production profiles and oversizing ratios calculated in Phase 2	To increase the specificity of H_2 storage costs	Brazil for example, has the highest seasonal variability in hybrid solar and onshore wind capacity factor, leading to H2 storage costs 200% higher than the average
The ability to modify capacity factor by region functionality removed from the model. Instead, varying region-specific production profiles can be used to observe the impact of capacity factor on LCOx, including the shape of the profile's impact on hydrogen storage requirements	Amplification of the load profile at a fixed capacity is not straightforward	

Detailed Description of Phase 2 Updates (3/3)

Update	Rationale	Effect
Discount rate set to 7% for all regions	This was done to compare mostly non-financial factors, aligning with most benchmarked studies. Flat rate of 7% was the average from these studies	As a result, the CAPEX cost component of LCOx is equal across regions, however, variation in cost mostly still comes from differences in capacity factors and oversizing
No-oversizing scenarios removed from the model	Hot and cold standby, as well as the variation in production efficiency based on variable load factor would have to be modeled adding complexity and cost. Also, real planned projects are typically not setup as such	Model is faster and results are easier to interpret
Liquefaction and transport costs broken out of the same cost component in the delivered cost results presentation	Based on a commentary from Phase 1	Drivers of cost difference are easier to interpret
Cost of storage required for production added to value chain storage cost component	To visualize cost drivers better	Easier to visualize the overall difference in storage costs
Ability to choose RES or grid power for production and value chain CI added	To assess the admissibility of various value chain configurations under European and Japanese rules	New gas production typically must use dedicated RES or PPAs to qualify under import CI standards
Brazil and Chile added to the model, as well as **multiple sub-regions in which RES capacity factors are used including** • North Africa (Egypt – Ain Sokhna, Tunisia – Tripoli, Morocco – Jorf Lasfar) • Middle East (Saudi Arabia – NEOM, Oman – Duqm, UAE – Abu Dhabi) • Australia (Pilbara) • Chile (Atacama, Magallanes) • Brazil (Ceara)	To model the difference in capacity factor by specific region and RES technology using Renewable Ninja	Hybrid solar and wind almost always yields lower LCOx, especially in regions with good diurnal profiles and high capacity factors like the Middle East and Chile

GIIGNL

WP3 – Regulatory Analysis and Market Frameworks

Including examples of viable supply chains from modeled results

Competitive Imports to Europe 2030

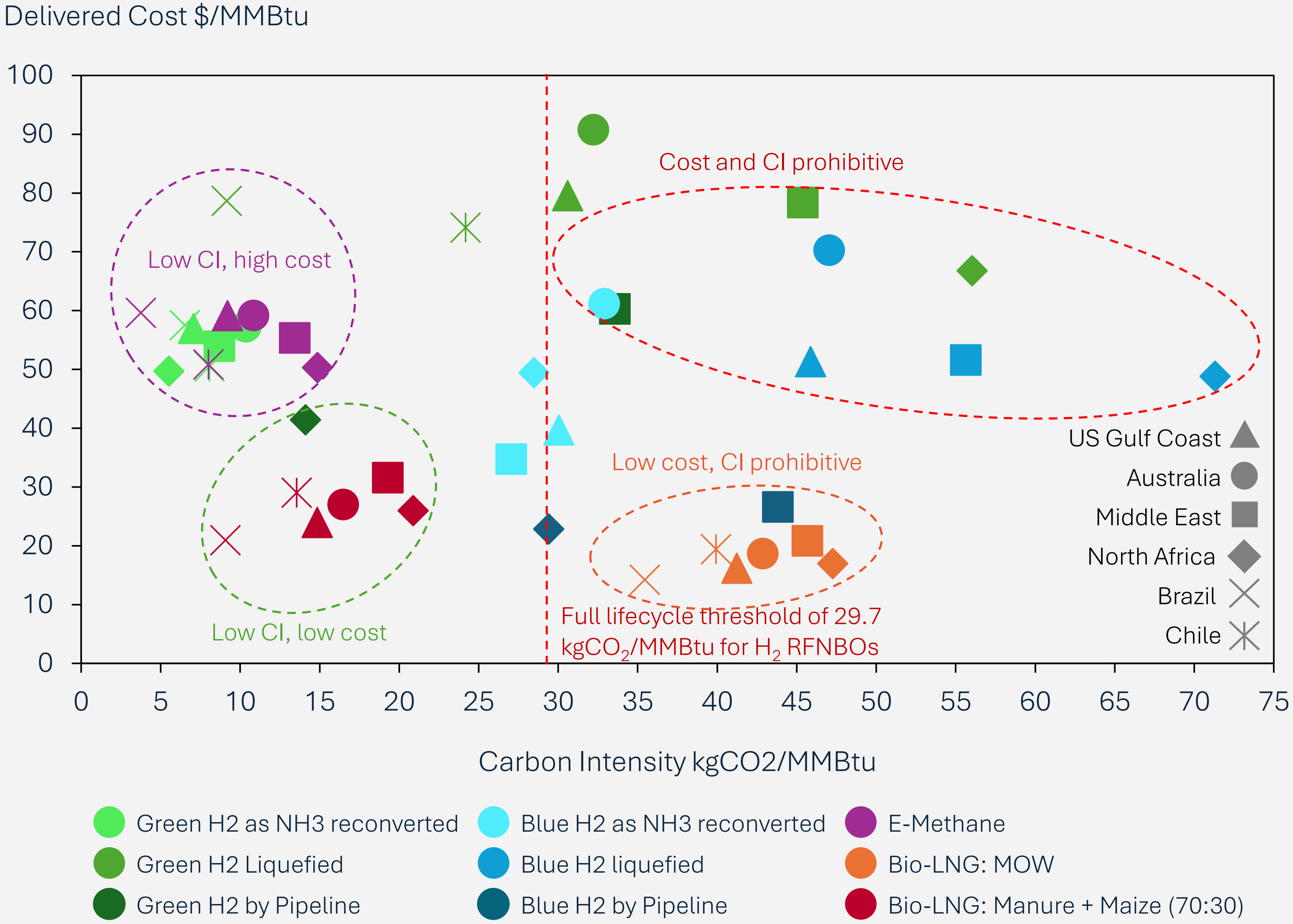
The most competitive and lowest carbon imports theoretically come from bio-LNG from either manure or partial manure feedstocks, **but not many regions are planning to export towards Europe**. **Piped green H_2** from North Africa and **blue NH_3** from the Middle East **are low cost and likely qualify as RFNBOs**.

The least carbon intensive value chains, **green NH_3 and e-methane**, are expected to be higher cost in 2030. It is assumed that e-methane is produced using biogenic CO_2 in 2030 from a pulp and paper mill at $200/t$CO_2$ as developers future-proof for RFNBO regulations.

If gases are not RFNBO certified, they are subject to CBAM pricing on their electricity related emissions *(not included in this graph)*

Cost and Carbon Intensity of New Gases Delivered to Europe 2030

Renewable powered production and local grid powered value chains



Competitive Imports to Japan 2030

Similar to European imports, the most competitive and lowest carbon imports theoretically **come from manure-based bio-LNG**, however scant volumes are expected to materialize

Blue and green NH_3 reconverted, and e-methane fall withing the carbon intensity thresholds, with **Australia and the Middle East being the most cost competitive suppliers for Japan**

E-methane is assumed to be produced using fossil CO_2 from a gas processing plant at \$20/tCO_2

Liquid H_2 imports are exceedingly expensive and carbon intensive in 2030 even from Australia

Cost and Carbon Intensity of New Gases Delivered to Japan 2030

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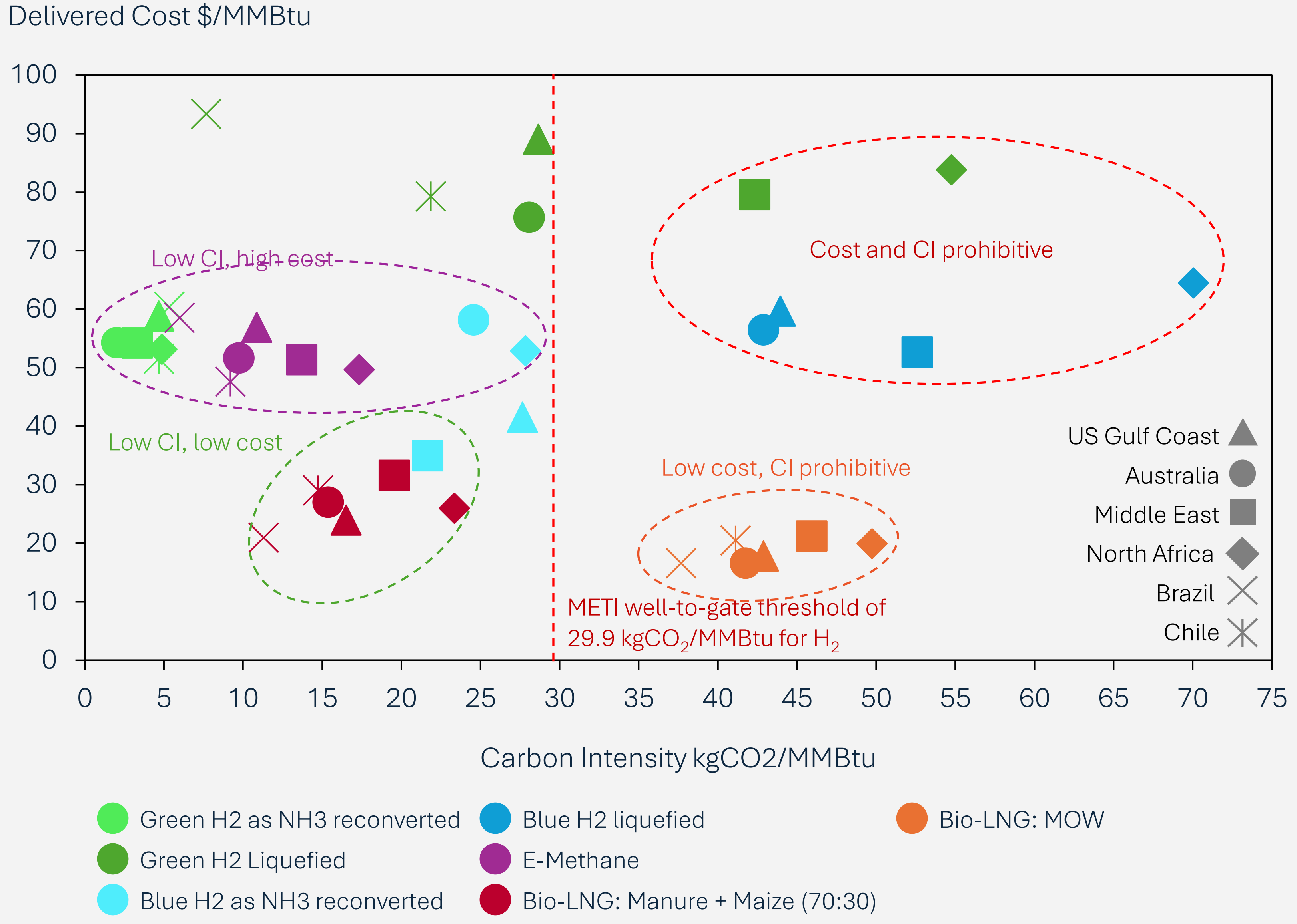


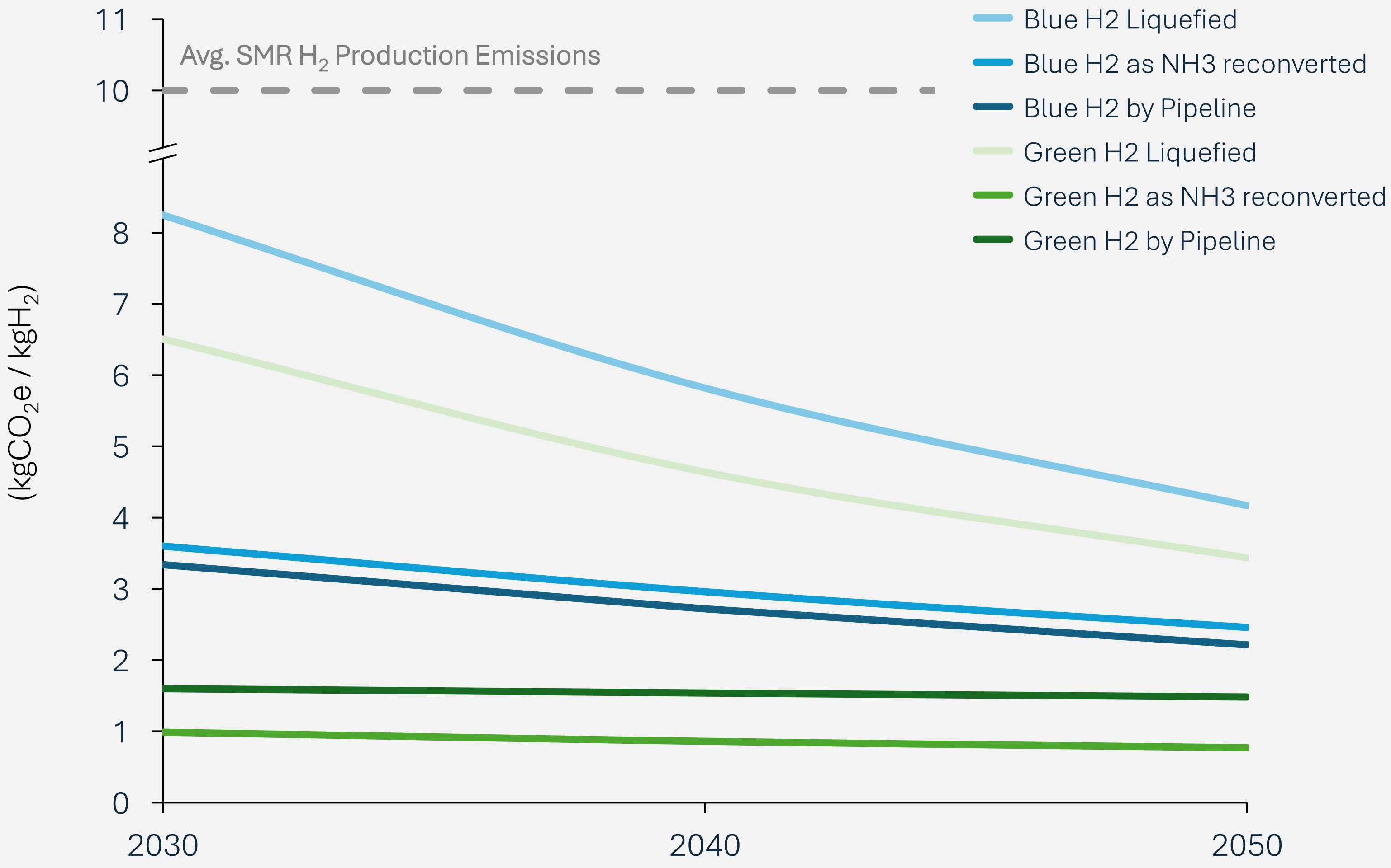
H_2 Value Chain Emissions

Over time, the largest drivers of efficiency improvements are expected in electrolysis, ammonia cracking, and liquefaction; efficiency improvements also lead to **reduced emissions intensity and delivery costs**.

Blue H_2 supply chain emissions intensity is expected to decrease along with upstream emissions from natural gas flaring and leakage, however both blue and green H_2 supply chain emissions intensities would be **2-3x higher than depicted** if local grid emissions intensities were used **instead of green PPAs for H_2 production**

Emissions Intensity of Clean H_2 Value Chains

H_2 value chains will improve in both efficiency and emissions intensity over time, increasing their attractiveness as decarbonization vectors



Shipping route: Middle East to Europe. Pipeline route: North Africa to Europe. Blue H_2 produced via ATR + CCS, with responsibly sourced gas at an upstream emissions rate of 1% in 2030, decreasing to 0.1% in 2050. It is assumed that renewable power is used for gas production, and local grid intensity is used for the value chain including compression, storage, reconversion, and liquefaction. Fully decarbonised shipping not assumed

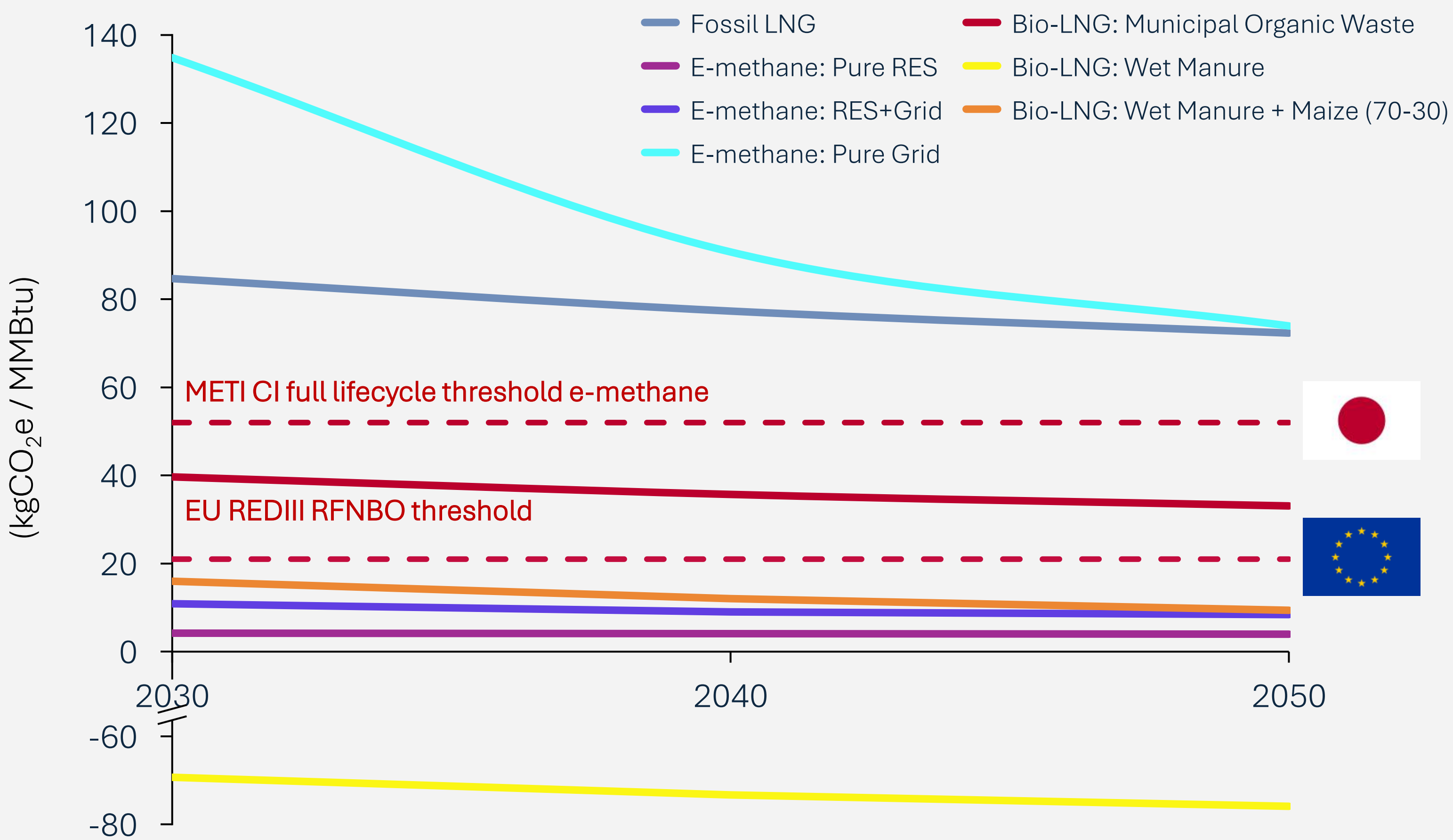
CH_4 Value Chain Emissions

Efficiency of the e-methane supply chain increases greatly over time due to improvements in Sabatier and electrolysis process efficiency from economies of scale, also driving emissions reductions.

E-methane produced from renewables in the US Gulf Coast and a grid powered supply chain falls below Ministry of Economy, Trade and Industry (METI) carbon intensity threshold of **46.7 $kgCO_2$/MMBtu well-to-gate** (the EU imposes a full lifecycle threshold of **26.7 $kgCO_2$/MMBtu for RFNBOs**). E-methane supply chain emissions intensity skyrocket if PPAs are not used throughout the supply chain, even if CO_2 is biogenic

Emissions Intensity of Clean CH_4 Value Chains

E-methane efficiency expected to increase greatly, emissions intensity will depend greatly on power source; bio-LNG feedstock may preclude imports



Supply chain: US Gulf Coast to Japan, from production to end-user. Exporting grid intensity: 0.38 $kgCO_2$/kWh (Texas), importing: 0.44 $kgCO_2$/kWh (Tokyo). Upstream LNG methane emissions reductions from 1% in 2030 to 0.1% in 2050 assumed. Emissions intensity includes combustion, e-methane and bio-LNG assumed carbon neutral due to biogenic feedstock. The gas itself is used to power compressors resulting in zero emissions at pipeline transport and storage steps for carbon-neutral fuels. It is assumed that renewable power is used for gas production, and local grid intensity is used for the value chain including compression, storage, reconversion, and liquefaction. Fully decarbonised shipping not assumed

Detailed Policy Assessment

EU – Overall Assessment of Regulatory Framework

First Movers | Environmentally Oriented | Complex: The EU has structured a **wide panel of subsidies, incentives and financial instruments** for all new gases in scope. However, the **approval process for granting these funds is long (12 to 24 months) and complex**, which slows down the implementation of projects and jeopardises the achievement of EU objectives. Also, it is not a given that EU-wide policy will translate into country-level developments: **only 6 out of the 10Mt of renewable H_2 production target by 2030 has been set by member states**[1]

Key Considerations

1. **Efforts for transport sector compliance now need to be extended** to other energy-intensive sectors; the current lack of clarity delays the adoption of new gases in these markets, slowing progress
2. Renewable gas PoS and GO reporting is currently disparate and complicates reporting, which is particularly cumbersome for small producers
3. Non-RFNBOs can still be used in Europe, but they will not count towards binding fuel quotas and may not qualify for incentives
4. The success of new gas deployment depends on the **effective transposition of EU legislation** into national frameworks
5. Interconnected gas grid **improves bankability and provides offtake optionality**

Major Policies and Impact

REDII/III

Ambitious binding targets for new gas uptake across sectors, although requires **stricter sustainability compliance** leading to larger **admin burden and project complexity**. Hinges on Member State transposition and enforcement

RED Delegated Acts

Stringent RFNBO requirements **ensure environmental integrity but raise costs** for exporters, who must invest in **dedicated RES and certification systems**. many developers call for leniency

The H_2 & Decarbonised Gas Package

Establishes a certification and Guarantees of Origin (GO) system recognizing renewable and low-carbon gases from non-EU countries, allowing imports to count toward EU targets. **Also provides tariff discounts for new gases**

H2Global

Provides a subsidy to **guarantee a viable price to exporters and importers of new gases to Europe**. It also reduces risk for EU utilities to buy ammonia/hydrogen by having an EU-backed intermediary. First project award in 2024 still awaiting FID

Largely Restrictive | Somewhat Restrictive | Somewhat Conducive | Largely Conducive

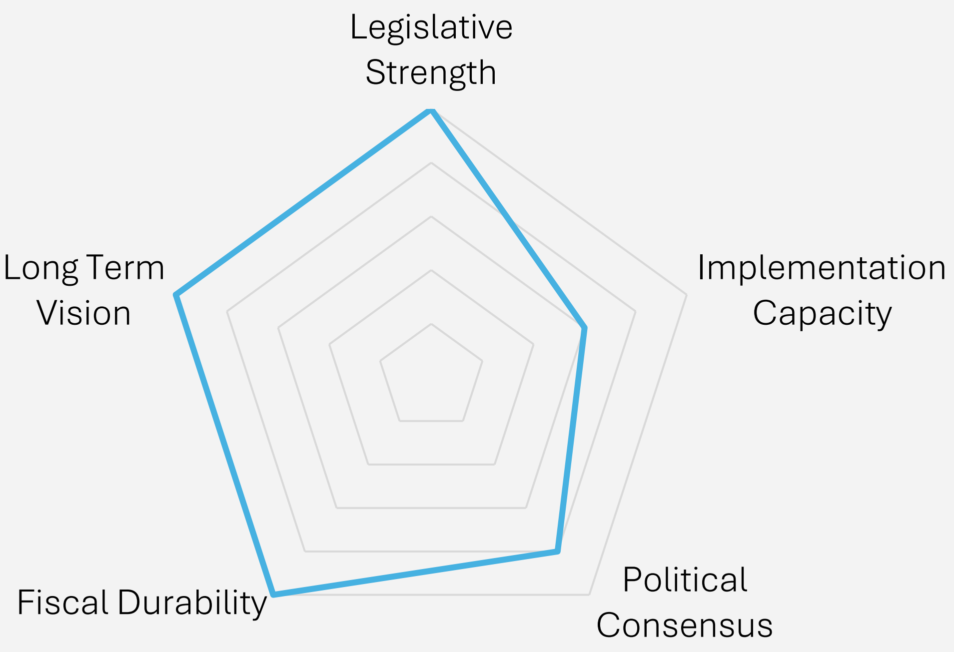
[1] EY

EU Regulatory Stability Assessment

Best-in-class legal scaffolding and multi-channel funding, but execution speed is the bottleneck

Ranking Matrix of Regulatory Staying Power

Overall: 22/25



[1]Billions of euros allocated, but only 21% of green hydrogen projects awarded IPCEI
[2]PP296_Populisme_Thalberg_EN_2.pdf

Legislative Strength

- Numerous support programs are in place to support investment into new gases, including the European Hydrogen Bank auctions (€ 3 billion), Innovation Fund grants (€40 billion for all technologies), IPCEI (up to €18.9 billion approved across member states for H_2), Connecting Europe Facility (~€1.85 billion), Modernisation Fund (ETS financed, >€15 billion since 2021), REPowerEU (Tops up MS measures, €27 billion for H_2 and €37 for biomethane) and other measures such as the Gas Package providing regulatory support (tariff discounts)

Implementation Capacity

- Money is moving, but advancement of projects is uneven: only ~21% of IPCEI-backed H_2 projects had reached FID, with delays in funding allocation occurring.[1] Execution will be the limiter, as markets and infra. are developing slower than expected. Permitting and RED transposition are barriers

Political Consensus

- The Green Deal direction holds, but post-2024 politics are more contested; policy continues yet faces pushback in some areas, as some believe spending on security must be hiked. A rightward shift in the political landscape is bolstering support against climate spending[2]

Fiscal Durability

- Multi-year, statute-backed framework with diversified, semi-earmarked funding. ETS revenues underpin a lot (with some near-term price volatility risk)

Long Term Vision

- Supply/demand targets were set but believed to be too ambitious and recently reduced. However, top-level vision is still one of the most ambitious globally, with projections that H_2 could make up 10% of the supply mix by 2050

Europe – New Gas Related Policy Impact

EU policies both encourage imports (through targets, funding, and infrastructure support) and impose strict standards (to ensure imports are truly low-carbon)

Policy	Description	Overall Impact	Incentives	Effect
Clean Industrial Deal (2025)	Clean Industrial Deal is a European Union initiative that forms part of the broader European Green Deal and the Net-Zero Industry Act (NZIA) framework. Its aim is to ensure that Europe's industrial base is globally competitive, climate-neutral, and resilient	EU reaffirmed the importance of hydrogen. Strengthens domestic production and innovation capacity within the EU. Simplifies state aid, permitting, and investment across EU Member States for clean H_2. Enhances the EU's strategic autonomy in energy and materials	Proposes finance and permitting relief	+
The Hydrogen & Decarbonised Gas Package (2024)	Sets market rules for renewable/low-carbon gases & dedicated H_2 networks, unbundling, TPA, certification. 100% tariffs discounts at production facilities, storage sites, and interconnection points (75% for low carbon)	Establishes a certification and GO system recognizing renewable and low-carbon gases from non-EU countries, allowing imports to count toward EU targets. It also empowers EU funding for cross-border H_2 pipelines. Defines low-carbon H_2	N/A (regulatory framework)	++
Alternative Fuels Infrastructure Regulation (2024)	Sets binding minimum targets for the establishment of publicly accessible charging infrastructure and specific targets for hydrogen refueling stations. Aims to ensure minimum hydrogen refueling stations infrastructure at 200-kilometer intervals throughout Member States	AFIR will indirectly benefit ship operators and airports as it will assist them in meeting the FuelEU Maritime and ReFuel EU requirements. Will help ensure interoperability of the infrastructure, improving implementation speed	N/A (mandate)	+
Carbon Border Adjustment Mechanism (2023)	Importers will have to declare the emissions directly linked to the production process, and if these exceed the EU standard, acquire an "emission certificate" at the price of CO_2 in the EU. Reporting obligations began in 2023 for carbon-intensive goods (incl. fertilizers and H_2/NH_3, excluding natural gas) and payment begins in 2026	Importers into EU will have to purchase CBAM certificates reflecting CO_2 emitted in production unless that CO_2 was abated or priced at origin. Provides a disincentive for imports of H_2/NH_3 produced from unabated fossil fuels by effectively adding ~$70-100/t$CO_2$ by 2030. This increases the competitive advantage for the lowest carbon gases especially as the ETS price is expected to rise	N/A (charge)	++

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

Europe – New Gas Related Policy Impact

EU policies both encourage imports (through targets, funding, and infrastructure support) and impose strict standards (to ensure imports are truly low-carbon)

Policy	Description	Overall Impact	Incentive	Effect
REDII/III (2018, 2023)	Introducing binding targets for the uptake of renewable hydrogen in industry and transport sector and aims to define green hydrogen-based gases through its RFNBO criteria and methodology	RFNBOs are expected to account for at least 1% of total energy supplied to the transport sector, and at least 42% of all hydrogen used in industry to be RFNBP by 2030, increasing to 60% in 2035, driving clean hydrogen for refining and ammonia	No EU-level cash (enables MS support)	++
RED Delegated Acts (2023)	Two delegated acts on the definition of renewable hydrogen: one sets criteria for renewable fuels of non-biological origin (RFNBOs); the other outlines how to calculate life-cycle emissions to meet EU greenhouse gas reduction thresholds	Stringent RFNBO requirements ensure environmental integrity but raise costs for exporters, who must invest in dedicated RES and certification systems. Although some flexibility is built in for projects built before 2028, many developers call for leniency. Gatekeeps the “renewable” status, could impact eligibility for other support	No (regulations)	-
REPowerEU (2022)	Sets non-binding H_2 and biomethane import targets in response to the 2022 energy crisis to reduce imports of Russian gas. 20 Mt of renewable H_2 and 35 bcm biomethane/biogas by 2030. Mobilizes €300bn grants and loans to Member States to 2030[1]	The import target sent a strong market signal and justified redirecting EU budgets (e.g. Innovation Fund, NDICI) toward facilitating imports, many import projects (ports, storage) are now labeled Projects of Common Interest, making them eligible for EU funding. Hydrogen diplomacy is bringing tangible results	Mobilizes €27 billion for H2 and €37 for biomethane	++
European Hydrogen Bank (2022)	Central EU funding instrument and coordination platform to secure hydrogen volumes in the EU – both domestic and imported. First auction in 2023 awarded €720 million to 7 renewable hydrogen projects, second auction Feb 2025 selected 15 projects to receive €992 million. Terms of second auction were more restrictive, limiting Chinese electrolyser stack components to 25%[2]	A third European Hydrogen Bank auction is planned for end 2025 with a budget of up to €1 billion. The Commission is developing the design of the international part of the European Hydrogen Bank that would attract imports of renewable hydrogen into the EU market. The aim is to bring together EU countries’ financial resources and potentially use H2Global as a vehicle for the international auctions	EUR 3 billion	++

[1]REPowerEU [2]European Hydrogen Bank - European Commission

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

Europe – New Gas Related Policy Impact

EU policies both encourage imports (through targets, funding, and infrastructure support) and impose strict standards (to ensure imports are truly low-carbon)

Policy	Description	Overall Impact	Incentives	Effect
Fit-for-55 (2021)	EU initiative setting legally binding targets for GHG reductions of 55% by 2030, and carbon neutral by 2050.[1] Delivered AFIR, CBAM, RED III, FuelEU, ReFuelEU, ETS2	Full implementation would lower fossil gas consumption by 30% by 2030, and create markets for new gases via various sub-legislatures, providing sticks and carrots	N/A (incentives emerging to support targets)	++
ReFuelEU Aviation (2023)	Sets out targets for both advanced biofuels and green synthetic fuels (e-fuels). Enforces a blending obligation on fuel suppliers for SAFs and sub-target for fuels derived from green H_2: 1.2% by 2030, 5% by 2035 & 35% by 2050	Since ReFuelEU is a regulation, not a directive, it is will be met with penalties, to be applied by Member States in many cases equal to or greater than the cost of adopting the clean fuel. For this reason, it is as a strong driver for uptake	N/A (market mandate)	++
FuelEU Maritime (2023)	Sets a limit on the GHG intensity of maritime fuels used by large ships, starting with a 2% decrease by 2025 and reaching up to an 80% reduction by 2050 (compared to reference value of 91.16 g CO_2e per MJ) tied to a non–compliance penalty of 2,400 €/t of very low sulfur fuel oil	21.6 TWh/y of Bio-LNG capacity installed in 2023 and 2024 combined on the EU, with bullish outlook for 2025. 'Multiplier' to be used when calculating the GHG intensity of the energy used allowing the energy from RFNBOs to count twice	Multiplier for RFNBOs provides incentive	++
H2Global (2021)	Tenders long-term purchase contracts for green ammonia, methanol, or hydrogen produced outside the EU, then resells within EU, covering the price via CfD	Effectively a subsidy to guarantee a viable price to exporters of new gases to Europe. It also reduces risk for EU utilities to buy ammonia/hydrogen by having a EU-backed intermediary	>EUR 6 billion	++
ETS Innovation Fund (2020)	With a revenue of €40 billion from 2020 to 2030 from the EU Emissions Trading System (ETS), the Innovation Fund aims to create financial incentives for companies and public authorities to invest in cutting-edge low-carbon technologies and support Europe's transition to climate neutrality	Over EUR 2 billion allocated to 30 H_2-related projects to date, and 1.7 billion for chemicals including clean NH_3 and e-methanol. The fund is highly beneficial but criticized for its complexity and speed: out of 337 proposals submitted for the fourth Innovation Fund call, 52 mostly submitted by small, medium, and pilot categories were considered ineligible	EUR 40 billion, not exclusively for H_2	++

[1] Fit for 55 - Consilium

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

Europe – New Gas Related Policy Impact

EU policies both encourage imports (through targets, funding, and infrastructure support) and impose strict standards (to ensure imports are truly low-carbon)

Policy	Description	Overall Impact	Incentives	Effect
Union Database for Biofuels (UDB – 2018)	The UDB tracks liquid and gaseous transport fuels under RED, used for mass-balance tracking and a Proof of Sustainability ledger for grid-injected biomethane to the point of consumption for compliance, particularly for transport	Reduces double-counting risk, but adds admin overhead. For RED counting to avoid heavy compliance penalties and (from 5 Aug 2025) to obtain the 100% interconnection-tariff discount for renewable gas shipments, network users must provide a UDB-registered PoS. Ambiguity between linkage of EDB and GO registers could cause credibility if not resolved	N/A	+
ERGaR / national GO registries / AIB	Guarantee of origin (GO) registers used to account for renewable gas consumption, disclosure purposes only in voluntary markets. AIB national register integration system received 8 new members in 2024, but remains the under used compared to ERGaR for now[1]	Enables the proper monetization and trading of GOs which herald a premium for biomethane in markets such as the Netherlands, Germany, France and the UK for example ranging from 5-50EUR/MWh depending on the market and feedstock. (historic height in 2023 for Danish GOs)	Fluctuating market price for GOs	+
Biomethane Industrial Partnership (2022)	Public-private partnership to unblock barriers for REPowerEU 35 bcm renewable gas target, the Commission and sector estimates point to €37 bn of targeted investments via EU instruments and ~€70–80 bn total capex needed	35 bcm target seen as unrealistic given that installed plant capacity just hit 7bcm in 2025 Q1, up 9% from 2024, is not increasing fast enough year on year. There is a wide investment gap that requires increased support	N/A	+
Interconnected EU Gas Grid	Under RED governance and the UDB, clean methane injected anywhere in the interconnected grid can be matched with withdrawals elsewhere for transport uses, so long as sustainability certificates and chain-of-custody are respected. This "virtual" flow underpins corporate and fuel-supplier claims	Mass-balance, certificate portability, tariff discounts convert the EU grid into a single market for green methane attributes. This improves offtake optionality (sell to the best buyer anywhere), reduces basis risk between injection and demand hubs, and raises project bankability by cutting network costs and smoothing claims across borders	N/A	++

[1]Veyt 2024 biomethane overview and 2025 outlook | Veyt

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

Europe – New Gas Related Policy Impact

EU policies both encourage imports (through targets, funding, and infrastructure support) and impose strict standards (to ensure imports are truly low-carbon)

Policy	Description	Overall Impact	Incentives	Effect
Important Projects of Common European Interest (IPCEI, 2022)	Until today, four IPCEIs in the hydrogen value chain have been launched. The four IPCEIs include 99 companies in 16 Member States and Norway mobilizing up to €18,9 billion in State aid across production, import, transportation as well as end use. It lets Member States fund the “funding gap” (CAPEX and sometimes OPEX) far above normal state-aid ceilings, provided the project has EU-wide spillovers, is highly innovative, and wouldn’t happen otherwise	Expected to unlock more than €27,1 billion of additional private investment. de-risks giga-scale electrolyser manufacturing, new H_2 production, storage/transport infrastructure and end-use (industry & mobility) by allowing very high public support where justified, typically as grants/repayable advances, often in multinational consortia	€18,9 billion	++
Delegated Act 2025/2359 on Low-Carbon Fuels (2025)	The law defines Low Carbon Fuels (LCFs) and sets the same emissions reduction threshold as RFNBOs at 70% GHG emissions reductions, in order for LCFs to qualify for incentives such as the Gas Decarbonisation Package tariff discounts and meeting renewable fuel quotas under REDIII. It does not provide guidance on how nuclear power would be treated as a feedstock for hydrogen production, expected in 2028. The methodology established in the delegated act provides a pathway for allowing electricity inputs used in the production of the LCF to be considered 0 $kgCO_2eq/MJ$, if the full load hours of the LCF production facility does not exceed the number of hours in which the marginal price of electricity was set by installations producing renewable electricity or nuclear power plants in the preceding calendar year for which reliable data are available	Hydrogen Europe said the exclusion of a specific methodology on nuclear-powered electrolysis using PPAs was a setback for a number of projects planning to report emissions intensity of their national grid Where the full load hours of the LCF production facility exceeds the full load hours of the renewable generator, grid electricity used in the production process of low-carbon fuels shall be attributed a greenhouse gas emissions value of 183 g CO2eq/MJ, which would be highly penalizing under CBAM. A portion of embedded lifecycle emissions for LCFs (up to 30%) will still be subject to ETS and CBAM pricing, which gives an edge to RFNBOs which are considered fully carbon neutral. Many LCF project cancelations have cited policy favoritism for RFNBOs as a reason.	NA	-

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

Europe – Renewable Energy Directives (REDII/III) Deep Dive

The RED III establishes binding renewable energy targets for all EU Member States, to be implemented at a national level, and provides a definition of green hydrogen-based gases through its RFNBO criteria and methodology

2025: Member States were supposed to transpose targets into national law by May 21, 2025 – progress has been sporadic so far

2023: REDIII implemented, introducing RFNBOs for compliance and updating sectoral renewable energy targets:

- At the EU level, a 42.5% share of renewable energy in the overall energy mix must be achieved by 2030
- In the industrial sector, **42% of hydrogen consumed for energy or feedstock must be RFNBO by 2030, and 60% by 2035**;
- In the transport sector, by 2030 Member States must either:
    - Increase the share of renewable energy in transport to at least 29%; or achieve a minimum 14.5% reduction in the greenhouse gas (GHG) intensity of transport fuels;
    - The combined share of biofuels, biogas, and RFNBOs must reach at least 5.5% of transport energy consumption
        - Within this 5.5% target, a **minimum of 1% must come specifically from RFNBOs**

2018: REDII implemented, setting a renewable energy binding target of 32% energy use by 2030, in the case of fuels only applying to the transport sector

Key Requirements:

- According to the RED III, whether hydrogen and derivatives qualify as RED compliant RFNBOs depends on:

  Criterion I: The electricity used for the hydrogen production

  Criterion II: The percentage of GHG emissions savings is generated with the hydrogen production. Primarily that RFNBOs must achieve **at least 70% GHG savings** compared to a fossil fuel comparator (94 gCO_2e/MJ)

  Criterion III: The mass balance and traceability in the supply chain. stipulating that sustainability information for RED-compliant RFNBOs must remain physically linked to the respective RFNBO. The mass balance system governs the production, purchase, and sale of RFNBOs that meet RED criteria, enabling the issuance of Proofs of Sustainability (PoS)

Criterion I and II are treated by the principles laid out in the two Delegated Acts for RFNBOs elaborated on in the following slides

[1]Renewable hydrogen - European Commission

Europe – REDIII First Delegated Act on Electricity Use (1/2)

Sets out requirements for electricity used in H_2-based fuels produced via electrolysis to qualify as an RFNBO

Main Guidelines for Hydrogen and Derivative Production :

Two main value chain configurations for RFNBO qualification:

Option 1: direct connection to an installation generating renewable electricity as fully renewable (article 3):

- Direct line OR production of renewable electricity and RFNBO within same installation;
- Renewable electricity production installation came into operation **not more than 36 months before RNBO production installation**; and
- No grid connection OR grid connection with smart metering system showing that no electricity has been taken from the grid for RFNBO production

Option 2: electricity taken from the grid as fully renewable (article 4): Either

- RFNBO production facility located in bidding zone where the average **proportion of renewable electricity exceeded 90% in the previous calendar year** and the production of renewable liquid and gaseous transport fuel of non-biological origin does not **exceed a maximum number of hours set in relation to the proportion of renewable electricity** in the bidding zone/country; or
- RFNBO production located in a bidding zone where the **emission intensity of electricity is lower than 18 gCO2eq/MJ** (subject to further criteria being met)

Key Takeaways

- The rules are to ensure that these fuels can only be produced from "additional" renewable electricity generated at the same time and in the same area as their own production
- Requirements apply to **both domestic producers and producers exporting to the EU**
- The Delegated Acts require **physical correlation, not just virtual or book-and-claim accounting for electricity**, mass balance must be used if equipment is only partially powered by renewables via PPAs for example at liquefaction plants blending RFNBOs with fossil gas
- To support early scale-up, renewable H_2 producers can sign long-term renewable power purchase agreements with **existing renewable installations until 1 January 2028**. This delegated act is subject to a review in July 2028

Europe – REDIII First Delegated Act on Electricity Use (2/2)

Sets out requirements for electricity used in H_2-based fuels produced via electrolysis to qualify as an RFNBO

Principles of Additionality, Temporal and Geographic Correlation

RFNBOs must be produced with electricity from the grid which complies with the conditions on additionality, temporal correlation and geographic correlation – ensuring that RFNBO production contributes to renewable power expansion:

- **"Additionality"**: Renewable plant commissioned **within 36 months of RFNBO production installation**. Only applicable to facilities commissioned beyond January 1st 2028) and has not received support in the form of operating aid or investment aid (but subject to exceptions)
- **"Temporal correlation"** Must prove **monthly correlation** of renewable energy generation and RFNBO production before **1 January 2030**, **moving to hourly afterwards**. Automatically fulfilled if the day-ahead electricity price is lower than EUR 20/MWh or lower than 0.36 times the EU emissions trading system (ETS) price
- **"Geographic correlation"** Electricity must be sourced within the same "bidding zone", a geographical area in which bids and offers from participants in an electricity market can be matched without cross-zonal capacity. If the electricity grid of the country is integrated and there are no geographically differentiated electricity prices, the whole country could be considered as one bidding zone

Key Takeaways

- PPAs can be used for any part of the supply chain but must comply with delegated act additionality, temporal and geographic correlation
- Additionality requirements specify that, where there is no "direct connection", the electricity generation source **must not have benefited from state aid**, preventing it from being eligible for RED fuel quotas
- In certain cases, it is also possible to produce RED compliant RFNBOs without a PPA between the renewable electricity plant and the hydrogen production plant in place, either if the
  - i) Share of renewables on the grid is >90% or emission intensity of electricity is lower than 18 gCO_2e/MJ
  - ii) Curtailment is reduced i.e. the used electricity reduces the need for re-dispatching of renewable electricity generation

Europe – REDIII Second Delegated Act on GHG Accounting

Defines the thresholds for GHG emissions savings that must be made for a gas to qualify as an RFNBO

Emissions Accounting Guidelines:

Total reductions: The GHG savings from the use of RFNBOs must be **at least 70% when compared to the fossil fuels which are being displaced** (RFNBOs use 94 g CO_2e per MJ H_2 as the benchmark); meaning the overall GHG emissions intensity of the RFNBO must be no greater than 3.4kg of CO_2e per kg of H_2 (in volumetric terms) or 28.2g CO_2e per MJ (in energy terms)

Accounting boundary: Takes into account GHG emissions across the full lifecycle of the fuels, including upstream emissions, emissions associated with taking electricity from the grid, processing, and transporting the fuels to the end-consumer

Electricity emissions: Any electricity used in the process which satisfies the First Delegated Act will be attributed zero GHG emissions under the Second Delegated Act

a) If electricity is sourced through a direct line or through a grid connection with a PPA following rules on additionality, temporal correlation and geographic correlation, **the electricity has an emission intensity of 0 gCO_2e / MJ**

b) If electricity is sourced from the grid without a PPA. a grid average emissions factor is applied unless a mechanism is in place (e.g., guarantees of origin, PPAs) to demonstrate renewable origin

Key Takeaways

1. Most jurisdictions in scope do not have grids with emissions intensities low enough to produce RFNBOs without PPAs compliant with Delegated Act rules along the value chain, **expect Brazil**
2. For certification of renewable hydrogen, producers will be able to rely on a well-established system of certification by third parties, so-called voluntary schemes of which 18 are currently recognized[1]
3. The Delegated Act proposes to restrict the types of CO_2 that can be used for fuel production to biogenic, particularly after 2035 for power and 2041 for industry. The long-term goal is to prevent RFNBOs from dependence on carbon generated from non-sustainable feedstock and therefore reduce the combustion of non-sustainable fuels and any associated carbon capture

[1]Voluntary schemes

Europe – EU Hydrogen and Decarbonization Package

The Gas Package is aimed at reforming the existing EU regulatory framework to support the deployment of renewable and low-carbon gases, in particular H_2 and biomethane, and enables repurposing of natural gas infra. through specific measures

2025: The Gas Regulation was fully applicable as of 5 February 2025, while Member States have until August 2026 to adapt national legislation to implement the Gas Directive, as it pertains to the measures below

2024: The package consists of EU Regulation 2024/1789 (Gas Regulation) and EU Directive 2024/1788 (Gas Directive). Numerous measures aimed at reducing costs of hydrogen uptake were imposed:

1. An obligation on Member States to enable the access of renewable and low-carbon gases to the market and infrastructure
2. Obligations for LNG and natural gas system operators to assess, at least every two years, the possibility of new investments to allow the use of renewable and low-carbon gas based on market demand
3. Member States to adopt **network tariff discounts of 100% for renewable gas and up 75% for low-carbon gas**
4. **Adoption of a joint purchasing mechanism** for hydrogen under the European Hydrogen Bank supervision
5. Provides the EC with power to adopt network code or implementing acts providing **common specifications for renewable and low-carbon gas**
6. Provides for the **prohibition of long-term contracts for the supply of unabated fossil gas concluded with a duration beyond 31 December 2049**

Key Requirements:

The Gas Package provides for two key sets of rules relating to market design, to guarantee a competitive and open hydrogen market: unbundling and third-party access (TPA)

1. **Unbundling:** the Directive sees ownership unbundling as the primary solution for production or supply and network infrastructure
2. **Third Party Access:** The Gas Directive states that access to hydrogen networks and storage facilities is subject to a regulated TPA regime, while access to terminals is subject to negotiated TPA. There is an option for Member States to allow for a negotiated TPA to hydrogen networks until 31 December 2032. Nevertheless, access can be refused in case of lack of capacity or connection or in other limited circumstances, for example, planned decommissioning of the relevant infrastructure or major infrastructures such as hydrogen terminals or hydrogen interconnectors

Europe – Delegated Act on Low-Carbon Fuels

Defines the thresholds for GHG emissions savings that must be made for a gas to qualify as an

Low-Carbon Fuels in the EU (Delegated Act 2025/2359)[1]

The law defines LCFs as all **non-renewable based and non-recycled carbon-based fuels** with **lifecycle GHG emissions at least 70% lower versus designated fossil benchmarks** (or that are renewable based but do not meet the RFNBO requirements)

- Translates to a maximum lifecycle emissions of 28.2 g CO_2e/MJ (3.38 kg CO_2e/kg of H_2)
- The methodology to determine the greenhouse gas emissions savings from low-carbon fuels is set out in the new Delegated Act (2023/2405)
- It applies a comprehensive lifecycle approach, accounting for feedstock extraction, processing, transport, combustion, methane leakage, and CCS performance
- Default lifecycle emissions for natural gas feedstock (set to 4.9 g CO_2e/MJ, lowered from 8.4 gCO2/MJ), methane intensity calculation at the production level methodology to be made available by the Commission by 5 August 2027
- The methodology references the EU Methane Regulation, underscoring that methane results must align with EU rules
- **Nuclear-powered LCFs or electricity sourcing remains under review**—with a specific methodology put out for consultation in 2026, **full rules expected by 2028 July 1**
- Captured CO_2 can either be permanently stored in geological underground formations or chemically bound into long-lasting products (**not stored in fuels**)
- **Biomass/biofuels may be used as fuels in the production process to lower emissions**

Lifecycle obligations: The act enforces a full **chain-of-custody MRV**. Companies must report all emissions along the supply chain, including transport, processing, and CCS losses, or risk non-compliance

Key Takeaways

1. Hydrogen Europe said the delegated act would provide legal certainty to project developers, but some say it "imposes **disproportionate reporting obligations and bureaucratic hurdles** that many hydrogen pioneers will struggle to manage"
2. The exclusion of a specific methodology on nuclear-powered electrolysis using PPAs was a **setback for a number of projects planning to report emissions intensity of their national grid**[2]
3. Only certified low-carbon hydrogen qualifies for tariff discounts, subsidies, state aid, or quota compliance under EU laws. However, **all embedded emissions are still subject to CBAM and ETS unlike RFNBOs** (except for in one possible case where FLH of LCF production does not exceed renewable/nuclear electricity generation marginal pricing, even still, only the LCF production related electricity emissions would be counted as 0 CO_2eq/MJ and not the value chain)

[1]Delegated regulation - EU - 2025/2359 [2]Hydrogen Europe

Europe – H2Global

Hintco, the H_2 intermediary company, creates markets by trading clean H_2, its derivatives, and other low-emission fuels aiming to create price transparency, provide legal certainty, and enable FIDs for clean fuel export projects

2025: Second H2Glboal auction led by German and Dutch governments providing up to €2.2bn ($2.27bn) and €300m of funding, respectively began in February 2025 with a **revised structure designed to foster competition and enhance supply chain flexibility**. It includes **four regional product-open lots and one global vector-open lot**, offering bidders greater flexibility in hydrogen transportation. Regional grouping are North America, Asia (including the Middle East), Africa, and a single auction incorporating both South America and Australia

2024: H2Global first pilot auction completed securing 397,000 tons at 1,000 €/t. CAD 300m earmarked by Canadian government to mechanism (Hintco) and AUD 330m earmarked by Australian government

2023: EUR 300m earmarked by Dutch government to mechanism (Hintco), EUR 3.53bn allocated by German government. Corporate donors at 49

2021: H2Global Foundation established with the support of 18 founding companies, and Hintco, the H2Global intermediary, is established. EUR 900m allocated by German government to mechanism (Hintco)

How it works:

- Hintco secures production through long-term purchase agreements and sells via short-term contracts
- To bridge the gap between the purchase and sale prices of clean fuels and their derivatives, Hintco uses concessionary capital to cover the green premium via Contracts for Difference (CfD)
- Hintco, a wholly owned subsidiary of the H2Global Foundation, operates independently from both government and industry, ensuring impartiality in its auction and trading processes
- Each funding body can design its own tender by defining the financing, product, geographical scope, sustainability criteria, and other individual requirements. This allows the provider of funds to tailor the tender to its specific objectives, such as promoting sustainable technologies, diversifying energy partnerships, or decarbonizing specific sectors

[1] Hintco-Fact-Sheet.pdf

Japan – Overall Assessment of Regulatory Framework

First Movers | Import Cost Reduction Focus | Non-Cumbersome: Japan's policy framework has evolved in recent years to address primary concerns around carbon intensity and cost premium of imported fuels, with clearer and stricter thresholds, **and a subsidy support scheme of >$20 billion expecting to catalyze around $80 billion in private investment in new gases** (¥100 trillion total). Although more work is needed around cross-border CO_2 accounting, their policy framework has no truly restrictive measures. They are non-biased against natural gas-based fuels such as blue NH_3, and have **less strict requirements for green H_2 and e-methane than Europe, which could lead to lower imported costs compared to Europe** as developers will have more project configuration options

Key Considerations

1. **Global competition for imports are intensifying**, and Japan could be in a bidding war against South Korea and Europe for lowest cost supply
2. Private sector targets such as the 1% e-methane blending in town gas objective by 2030 are also driving project development, and there is talk of transposing the target into law. **Pressure is on 2025 FID for meeting 2030 targets**
3. Japan's power market and auctions are regulated in a way that costs are passed to consumers; government support will be vital to keep these imports viable, hence the importance of the price gap subsidy CfD expecting awards in 2025 – **if it falters, demand might not scale as expected**

Major Policies and Impact

Hydrogen Society Promotion Act

Significant legislature marking a shift from R&D heavy support to **market implementation** of low-carbon hydrogen and derivatives via regulatory support programs. **Tightens carbon intensity standards**

Price Gap Subsidy (CfD)

A total of ~0.6 Mtpa H_2e per year could be unlocked through the program spread over the 15-year lifetime. Pivotal for meeting demand targets by 2030. First commitment of estimated $6.8B in 2025 for Blue Point Ble NH_3 in the US

Green Innovation Fund

Support for new gas technology pilots (often at 50–100% of cost) **reducing risk for commercial import projects** to follow and increasing investor confidence. Has demonstrated Liquid H_2 from Australia, NH_3 co-firing, e-methane production etc

Decarbonised Power Sources Auctions

20-year capacity payment support auction in which H_2 and NH_3 special treatment in 2025 revisions, increasing capacity support ceilings and adding variable cost support (not stackable with CfD)

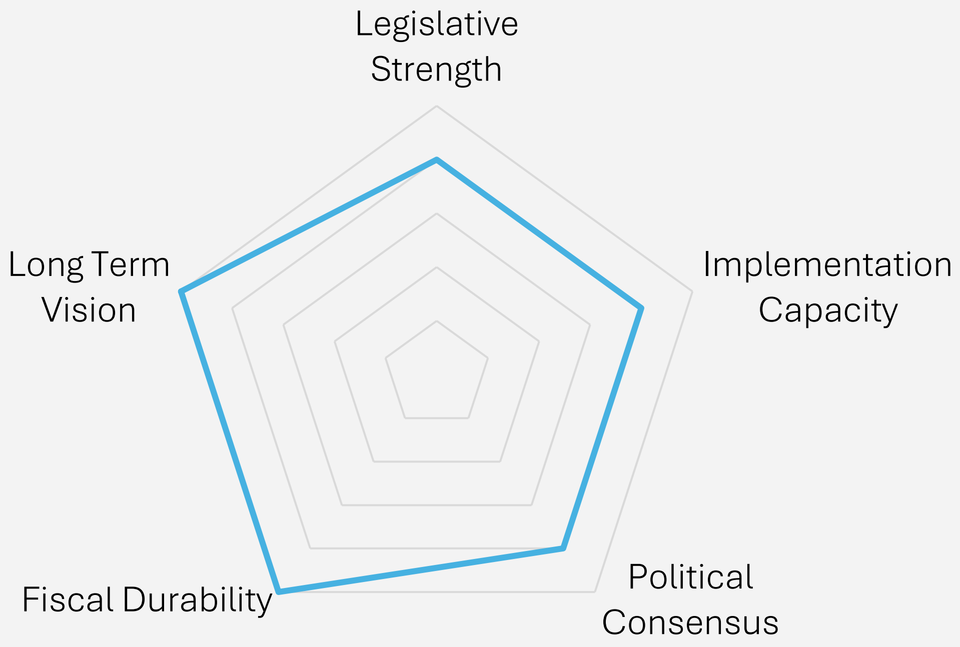
Largely Restrictive | Somewhat Restrictive | Somewhat Conducive | Largely Conducive

Japan Regulatory Stability Assessment

Tight, targeted subsidy architecture with long-tenor support and capacity payments; policy is strong but project uptake/costs will determine how much actually builds out

Ranking Matrix of Regulatory Staying Power

Overall: 22/25



Legislative Strength

- Japan plans to mobilize ~JPY 15 trillion (~USD 100 billion) in both public and private capital over 15 years to build its hydrogen/ammonia supply chains across the CfD style price gap support, hub subsidies, R&D funding and capacity payments for clean power. The GX Bonds are a fiscal backstop

Implementation Capacity

- Mechanisms are live (JOGMEC price-gap & hubs; OCCTO Long-Term Decarbonized Power Source Auction with 20-yr capacity payments), but early rounds show mixed uptake and growing scrutiny.[1] Japan has the technical know-how to implement projects as long as costs are acceptable

Political Consensus

- Cross-party appetite for energy security and transition remains, but Diet arithmetic has been volatile since late-2024 as there is no majority in the lower house.[2] Sectoral mandates (e.g., SAF) still spark debate[3]

Fiscal Durability

- GX Economic Transition Bonds (target ¥20T over ~10 years) finance transition supports; plus the ¥2T NEDO Green Innovation Fund and wider GX plan to mobilise ~¥150T public-private

Long Term Vision

- Quantified supply targets (H_2/NH_3 3 Mt by 2030 → 12 Mt by 2040 → 20 Mt by 2050) and cluster build-out; execution & cost realism are active watch-points

[1] Renewable Energy Institute [2] Japan News and Analysis [3] Reuters

Japan – Summary of New Gas Related Policy

Japan is steadily ramping and diversifying support, as well as improving regulatory clarity around new gas related standards

Policy	Description	Overall Impact	Incentive	Effect
Japan's Strategic Energy Plans (latest 2025)	Sets target for ~1% H_2/NH_3 in the power fuel mix by FY2030–31. Quantitative language around H_2 and NH_3 for power in the 7th SEP is toned down, and qualitative language around the drop-in e-methane is enhanced[1]	In 2025, some Japanese refiners trimmed near-term H_2/NH_3 ambitions citing costs/returns. Japan sees a bigger but undefined role for e-methane in the future, as a potential replacement for natural gas supporting a potentially significant transition	N/A (Strategy)	+
Green Transformation (GX) Programme (2024)	The GX Strategy is a comprehensive, legally-backed roadmap aiming to drive public-private investments of JPY 150 trillion (~USD 1 trillion, nearly 3x the annual GDP investment % of the US IRA) over 10 years to enable Japan's transition to a net-zero economy by 2050 mainly through public finance spine of ¥20 trillion GX Economic/Climate Transition Bonds. Includes emissions trading system (starting trials FY2026), carbon surcharges on fossil fuel importers (from FY2028) and emissions allowance auctions by power generators (FY2033)	The Hydrogen Society Promotion Act is enacted under the GX umbrella. Empowers JOGMEC to run price-gap (CfD-style) subsidies for clean H_2/NH_3/e-fuels and hub (infrastructure) support across the supply chain. These mechanisms de-risk early imports and domestic production and are the main route by which GX money reaches H_2 and derivatives. Initial bond auctions haven't yielded a "greenium" (lower borrowing cost), with weak investor demand; uptake has relied heavily on the Bank of Japan and GPIF. Still, if bond proceeds start flowing meaningfully into R&D and industrial deployment, investor confidence is expected to grow	¥150 trillion (~US1 trillion) across entire program, not just new gases	++
Contract-for-Difference (CfD) Programme (2024)[3]	Price-support scheme led by METI for imported low-carbon hydrogen, ammonia, or synthetic fuels meeting carbon thresholds to bridge the cost gap with traditional fuels for 15 years. Legislation under the GX (Green Transformation) Act enables using carbon tax or bond revenue for these subsidies	A total of ~0.6Mt H_2e per year could be unlocked through the program spread over the 15-year lifetime of the program. the subsidy could amount to hundreds of billions of Yen per year for fuel purchases. Screening results expected in FY 2025-26	¥3 trillion ($20 billion)	++

[1]S&P Global [2]Japan's GX Plan [3]Japanese government allocates $21bn

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

Japan – Summary of New Gas Related Policy

Japan is steadily ramping and diversifying support, as well as improving regulatory clarity around new gas related standards

Policy	Description	Overall Impact	Incentive	Effect
Hydrogen Society Promotion Act (2024)[1]	Act is formally titled "Act on Promotion of Supply and Utilization of Low-Carbon Hydrogen and its Derivatives for Smooth Transition to a Decarbonized, Growth-Oriented Economic Structure"	METI and JOGMEC receiving and reviewing business plans, afterwards will disperse hub infrastructure and CfD funding and grant permit exemptions. This is expected to catalyze a string of FIDs up to 2027 in line with reaching 2030 H_2 and derivatives targets	CfD Price Gap Subsidy and H_2 Hub FEED Tender	++
H_2 Hub FEED Tender (2024)	Funding support FEED studies carried out for the development of low-carbon H_2 and derivatives hubs, to be carried out until February 2026, must involve at least 2 companies. They plan to support three large-scale and five medium-scale hubs over the next 10 years	The configuration of H_2 and derivatives supply chains will be ironed out in the coming years, collaboration across the value chain is encouraged and potentially preferred	¥5.7 billion ($38 million)	+
Basic Hydrogen Strategy (2023)	Updated strategy with more ambitious hydrogen and ammonia targets – 3/12/20 Mtpa of H_2 annually by 2030/2040/2050 respectively, acknowledging most will be imported	Foundation for all other measures, setting a clear long-term market signal. It calls for massive public-private investment (¥15 trillion (~$107 billion) over 15 years) in H_2/ammonia supply chains. Has been a major driver for international partnerships as well	N/A (funding instruments separate)	++
JOGMEC "Risk Money" Support	In the Basic H_2 Strategy update 2023, the Japan Organisation for Metals and Energy Security (JOGMEC) was empowered to assume risks that private investors might avoid, by providing equity capital and liability guarantees for the production and storage of decarbonised fuels (H_2, NH_3 and synthetic fuel)	Derisking of select projects to support establishment of new gas value chains. Feasibly will help to promote domestic production and imports	Dynamic support for defined risks	+

[1] Nagashima Ohno & Tsunematsu

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

Japan – Summary of New Gas Related Policy

Japan is steadily ramping and diversifying support, as well as improving regulatory clarity around new gas related standards

Policy	Description	Overall Impact	Incentive	Effect
Long-term Decarbonised Power Sources Auction (2023)	The Auction trades future capacity to produce electricity and is designed to encourage investments in new “decarbonised” power generation facilities. Thermal power using hydrogen and ammonia is one of the eligible power sources	The winning bidders will be contracted for a 20-year capacity payment, successful bidders are required to return between 85-95% of the additional profits they obtain from the projects. H_2 and NH_3 mono firing and co-firing given special treatment in 2025 revisions, increasing capacity support ceilings and adding variable cost support (not stackable with CfD)	Rate-payer funded scheme	++
Roadmap for Carbon Recycling Technologies (2019, 2023)	Japan’s national CCU/CCUS plan (first issued 2019, revised June 2023) led by METI/Agency for Natural Resources and Energy. It charts R&D-to-deployment pathways for mineralization (cement/concrete), synthetic fuels (e-methane, e-fuels), and chemicals. The GX framework and Japan Climate Transition Bonds are being used to fund carbon-recycling tech	MOF/METI documents show multi-trillion-yen issuance across FY2023–FY2025 with eligible uses including hydrogen/ammonia and industrial decarbonization that enable CCU pathways. E-methane (notably for city-gas blending and LNG value chains) and e-fuel pilots should expand where low-carbon power and electrolyzers are available; economics hinge on renewable/hydrogen costs and grid-matching rules for exports	GX/transition bonds	+
Green Innovation Fund (2021)	Initiative established by METI and led by the New Energy and Industrial Technology Development Organisation (NEDO), mobilizing government funding for R&D in 19 clean energy-related areas including H_2 and NH_3 supply chain establishment, H_2 production, H_2 use in steelmaking, next-gen ship development CO_2 based fuels and more for a 10-year period	Accelerates technology and infrastructure needed for imports (e.g. liquefied H_2 carriers, ammonia co-firing turbines). By subsidizing these pilots (often at 50–100% of cost), it reduces risk for commercial import projects to follow. Also funds supports international demonstration projects – e.g. the HySTRA project that shipped liquid H_2 from Australia to Japan in 2022. E-methane production trials have also been supported	¥2 trillion (~$19.2 billion USD) not all for new gases	++

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

Japan – Basic Hydrogen Strategy

Foundational strategy outlining the major priorities related to hydrogen and ammonia, sending a strong signal domestically and internationally that has spurred investment and international partnerships

2023: G7 commitments to move away from a reliance on Russian energy, growing calls for climate action, and new hydrogen subsidies under the EU's Green Deal Industrial Plan and the US' Inflation Reduction Act prompt an update in the strategy, increasing and detailing hydrogen and ammonia-related targets. Strategy expansion was backed by the Green Growth Strategy and Japan's carbon-neutral 2050 pledge. It broadened focus from fuel cells to using **ammonia in power generation** and **synthetic methane in gas networks**

The new hydrogen strategy also makes it clear that the Japanese government will **subsidise the establishment of the hydrogen supply chain** and the development of infrastructure based on "carbon intensity." Including

1. **Cluster development support** to establish internationally competitive industrial clusters and supply chains (1 trillion yen of public and private investment expected) and
2. **A producer support scheme** to expand the supply volume and reduce supply cost (more than 7 trillion yen)

2017: World's first Hydrogen Strategy released, aiming for 2 Mtpa of hydrogen use, mostly produced domestically[1]

Key Targets:

Hydrogen Consumption Targets (including ammonia):

- 3 Mtpa H_2 and 3 Mtpa NH_3 by 2030
- 12 Mtpa H_2 by 2040
- 20 Mtpa H_2 and 30 Mtpa NH_3 by 2050

Cost Reduction Targets:

- Cost targets for reducing H_2 import costs to ¥30/Nm^3 ($3/kg) by 2030 and ¥20 by 2050 ($2/kg)

Carbon Intensity Standards (revised standards since 2024):

- Hydrogen: ≤ 3.4 kg CO_2e/kg H_2 (well-to-gate)
- Ammonia: ≤ 0.84 kg CO_2e/kg NH_3 (gate-to-gate)

Electrolyzer Deployment & Investment

- 15 GW of electrolyzers installed by or made with Japanese components globally (~10% of the estimated market)

[1] Japan: hydrogen strategy - November 2023

Japan – Hydrogen Society Promotion Act (2024)

Technically Japan's first H_2 and derivative dedicated law marking a significant shift from R&D focused support to market implementation of low-carbon hydrogen and derivatives, and align standards with international counterparts

Strategic Objectives and Regulations:

The policy is structured to:

- Establish a policy framework to promote low-carbon hydrogen
- Introduce a business plan certification system (supplier + user plans) to access subsidies, tax incentives, and regulatory relief the law offers
- Enable public subsidies via two main schemes:
  - CfD: "Price Gap Support" Administered by JOGMEC after business plan approval by METI (¥3 trillion ~US19 billion budget)
  - Hub Development Support: Subsidies for FEED, engineering, and construction of domestic H_2/ammonia infrastructure hubs
- Offer regulatory exemptions (under Gas Safety, Road, Port Acts) for approved projects (up to 3 years' relief from key permits)
- Set supplier conduct standards and monitoring requirements

Updated carbon intensity standards :

- Aims to reduce CO_2 emissions of fuels by 70% compared with fossil fuel-derived production, in line with standards in Europe and the US
- Update of low-carbon ammonia emissions threshold to ≤ 0.87 kg CO_2e /kg NH_3 well-to-gate instead of gate-to-gate, effectively accounting for upstream methane leakage for blue NH3 facilities, and limiting it to ~2% across the system[1]
- E-methane threshold: ≤ 49.3 g CO_2e/MJ (well-to-wheel)

Key Takeaways

1. Approval of business plans means METI has increased jurisdiction on projects, and can ensure alignment with national decarbonization, security and industrial competitiveness (price and CI)
2. Even under this ramped framework, new gas imports into Japan are **less constrained than into Europe. Principles of additionality, temporal and geographic correlation do not yet apply**, meaning clean grid electricity can likely more often be used to produce molecules, and less overall capital expenditure is likely required if dedicated RES requirement is less

[1] Japan tightens low-carbon ammonia standards

Japan – Contract for Difference (CfD) Mechanism

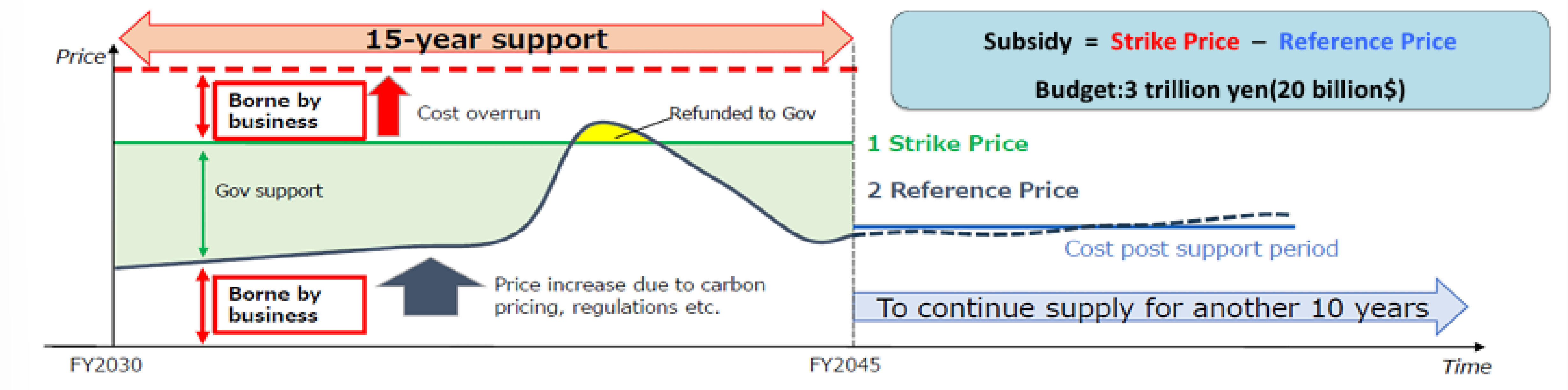
First round applications for the CfD exceeded the proposed budget, indicating resilient interest in the Japanese co–firing offtake market

2024/25: The first applications are under review (since late 2024), with selection expected in 2025. First award announced in November 2025.

2023: Green Transformation Promotion Act funding commitment for H_2 and NH_3, including the CfD mechanism stimulating imports particularly to support decarbonization of Japan's relatively young coal fleet

Key Requirements:

- Supply must start by 2030 and continue for another 10 years beyond 15-year price support
- Projects must have secured offtake agreements with buyers for at least 70% of their produced hydrogen
- Projects must have a capacity of at least 10,000 tons of hydrogen per year, and meet METI carbon intensity thresholds



3_Session_B-1_Overview_of_Japans_CfD_Support_Scheme_JOGMEC_Suehiro.pdf

Japan – Long-term Decarbonization Power Source Auction

20-year power purchase contracts for low-carbon generation including H_2 and NH_3 co-firing aimed at decarbonising power

2024: Second auction held in January, only one NH_3 co-firing bid and award of 95 MW for Shikoku Electric Power Company's Saijo Coal Power Station

Revisions to the upcoming third auction have been slated, following results of the first and second auction, which were criticized over awarding the large majority capacity to existing nuclear and LNG-fired thermal power plants

The revisions include **increase in price caps for CCS, H_2 and NH_3 a co-firing,** addition of H_2 and NH_3 mono-firing to the scheme, and includes a **variable cost support** for 40% of annual facility utilization rate for CCS, H_2 and NH_3

2023: Program created and first auction held as part of the capacity market, managed by Japan's grid coordination body (Organization for Cross-regional Coordination of Transmission Operators, or OCCTO)

- **How it works:** Levy collected by utilities as a surcharge on electricity bills and redistributed to the awarded generators in form of fixed capacity revenue support for up to 20 years
- **770 MW of capacity awarded for NH_3 co-firing retrofit, 55MW for H_2 co-firing**

Key Requirements:

Revised bid price caps for third auction are set at:

- Greenfield H_2 co-firing >10% (LNG): ¥134k/kW-year
- Greenfield H_2 mono-firing: ¥795k/kW-year
- Greenfield NH_3 mono-firing: ¥303k/kW-year
- Retrofitting H_2 co-firing >10%: ¥762k/kW-year
- Retrofitting NH_3 co-firing >20%: ¥378k/kW-year

These caps translate to roughly **~USD 37–76/MWh** depending on configuration after repayment (*Internal calculation, not official)*

Notably, hydrogen/ammonia power bidders can't "double-dip", costs supported under this auction will be discounted if already supported via the JOGMEC hydrogen CfD scheme

Additionally, the 6GW quota for FY2023-2026 was filled in the first year, so **additional 2GW per FY2024 and FY 2025 have been added**

[1] Long-term Decarbonization Power Source Auction

USGC – Overall Assessment of Regulatory Framework

Production Incentive Leader | Regulatory Uncertainty | Fossil-fuel advantage: Dynamic mix of tax credits, grants and market incentives that skew strongly toward **promotion of production** (with implicit support for future export capacity). Even with the reduced scope of 45V credits and uncertainty around H2Hubs, the US **still likely leads in direct subsidy support for new gases**. The IRA alone may represent $50–100+ billion in hydrogen and clean fuel subsidies through 2030, depending on uptake. Few policy restrictions are observed, but renewables based new gases facing much higher resistance under the current administration than natural gas-based ones. The biggest restriction comes from 45V Three Pillars and EU RFNBO compliance, which constrain developers and do not currently allow subsidized renewable power for European RFNBO status

Key Considerations

1. **Uncertainty around US tariffs are making developers and investors weary**, and could **raise construction costs** for new gas facilities. LSB put their proposed 1.1Mt blue NH_3 in Houston on hold in Q1 2025. Even projects beyond FID such as CF Industries, JERA and Mitsui Blue Point Complex in Louisiana report facing higher costs. Tariffs may however make meeting **domestic content adder easier** for IRA tax credits
2. Developers have complained about difficulty and administrative burden of **meeting apprenticeship and domestic cost content adders**
3. The U.S. requires Department of Energy approval for LNG exports to non-FTA countries, but in practice approvals are routine. Producers can claim IRA credits without a domestic-use requirement

Major Policies and Impact

IRA 45V H_2 Production Tax Credit

One of the most impactful incentives worldwide at full value of $3/kg H_2 making renewable based new gases produced in the US some of the cheapest worldwide. **Big Beautiful Bill shortens construction deadline to 2028**

IRA 45Q CCS Tax Credit

Fossil fuel-based industries such as natural gas are currently a priority in the US, **the $65/t$CO_2$ 45Q tax credit has been very successful** at spurring private investment in blue ammonia projects in the USGC

Infrastructure Investment & Jobs Act

Total $9.5 billion for clean H_2, with $8 billion to establish 7 regional H_2 Hubs which have been selected and expected to attract ~$50 billion in private investment, **proposed blocking of unawarded funding in Democratic states**

45V "Three Pillars"

Planning new renewables installations in places where interconnection queues are long such as Texas (although fast moving) increases development **timelines and levelized costs for green H_2 value chains vying for 45V**

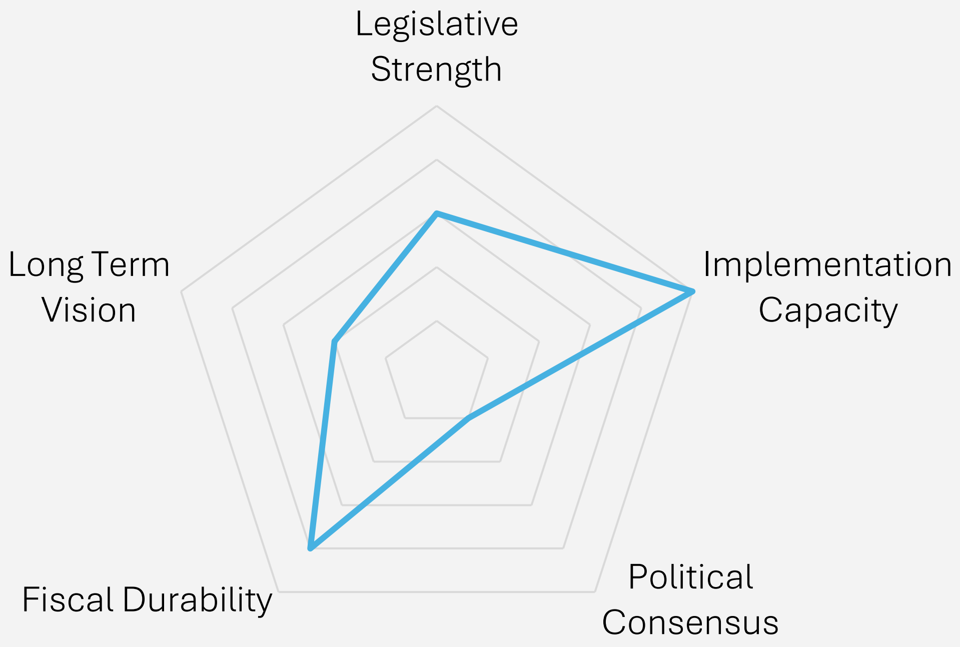
Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive

USGC Regulatory Stability Assessment

One of the strongest incentive packages for a single country, although bias and uncertainty has been recently introduced, shaking up the outlook

Ranking Matrix of Regulatory Staying Power

Overall: 15/25



[1] Inflation Reduction Act: global green hydrogen | EY – India
[2] Big Beautiful Bill Extends 45Q Clean Hydrogen Tax Credit | ESG Review

Legislative Strength

- The IRA tax credit and DOE Hydrogen Hub funding have been seen as some of the most impactful legislations, however many provisions related to green H_2 production have been reduced. The strength of this legislation will depend on its implementation, which is currently highly uncertain following the $2.2B funding pull from ARCHES and PNWH2 hubs

Implementation Capacity

- Many commercial and policy drivers such as faster permitting approvals that are causing new gas projects to develop faster than other regions[1]

Political Consensus

- The IRA is a bipartisan legislation that provides benefits for both sides of the political spectrum, however recent passage of the Big Beautiful Bill has revealed a lack of alignment on the solar, wind and green hydrogen components[2]

Fiscal Durability

- Tax-expenditure-based, which is vulnerable to political scrutiny. Recent reduction in scope of the tax credits provide less predictability to investors, and will mean the market has less time to mature before subsidies taper off specifically for green H_2

Long Term Vision

- Long term vision is relatively strong, with the DOE setting targets such as $1/kg H_2 and the scope of incentives extending 10 years beyond 2033 for 45Q for example. However, it is unclear exactly how new gases fit into the long-term strategy post 2025

USGC – Summary of New Gas Related Policy

Total costs of tax credits are very open-ended, depending on implementation, supply and demand dynamics, adherence to multipliers and content adders and political stability

Policy	Description	Overall Impact	Incentive	Effect
Clean Hydrogen Production Standard (CHPS, 2023)	Updated clean H_2 production guidance establishing a threshold of 4.0 $kgCO_2e/kgH_2$ for greenhouse emissions within the well-to-gate system boundary, accounting for multiple requirements within the IIJA provision and aligning with the 45V PTC.[1] Updated from a <2.0 $kgCO_2e/kgH_2$ threshold for production only to allow for more flexibility across a larger system boundary[1]	To receive IIJA funding, projects must at least "demonstrably aid" the achievement of the CHPS. Blue H_2 systems with 95% CCS, using the average US grid mix and ~1% upstream methane emissions could meet the threshold, as well as electrolysis systems sourcing ~15% of their electricity from the grid and the remainder from clean energy sources. Seen as a first step to accounting for full lifecycle emissions, as it does not include downstream distribution or component manufacturing emissions	N/A (improves qualification for IIJA/IRA funding)	+
National Clean H_2 Strategy (2023)	Comprehensive strategy and roadmap released in 2023, with near-term goals of 10 Mtpa clean hydrogen production and aligning with a "Hydrogen Shot" goal of $1/kg H_2 by 2031	While not legislation, it guides funding and regulatory efforts, and provides a degree of certainty for investors as to the DOE's ambition, who envision the U.S. as a top-3 hydrogen producer by 2030	N/A (mainly through IRA and IIJA)	+
Renewable Fuel Standard (RFS, 2005)	US-wide standard allowing producers of biomethane used as vehicle fuel (compressed or LNG) to earn Renewable Identification Number (RIN) credits required for meeting Renewable Volume Obligation (RVO) compliance. Cellulosic biogas (D3 RIN) credit prices have been high, effectively subsidizing biomethane production. Exporters of must meet obligations and exporters must calculate and report exporter-RVOs unless the fuel was obtained directly from the producer, and no RINs were generated[2]	Credits often range $10–$20 per MMBtu, substantially enhancing project revenues for domestic fuel producers. While originally for biofuels like biodiesel, this policy has driven a surge in renewable natural gas projects, indirectly supporting bio-LNG production for domestic road transportation, but increasing competition fiercely for already scarce biomethane resources for export, which domestic consumers are willing to pay more for to fulfil their compliance obligations. Also, if exporters of bio-LNG collect RINs they will have an additional compliance obligation	N/A	-

[1]Production Standard Guidance [2]Requirements for exporters

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

USGC – Summary of New Gas Related Policy

Total costs of tax credits are very open-ended, depending on implementation, supply and demand dynamics, adherence to multipliers and content adders and political stability

Policy	Description	Overall Impact	Incentive	Effect
Inflation Reduction Act (IRA, 2022)	The IRA offers tax incentives to accelerate decarbonization through cost reductions for emerging technologies, including clean electricity, H_2, CCS, and sustainable fuels. Over the next 10 years, it is estimated that the total public IRA spending will be between $936 billion $1.97 trillion[1]	Clean energy stocks fell sharply on the prospect of rollback (e.g., solar index plunged ~10%). Smaller developers are pausing or downsizing pipelines; Houston Chronicle reports $8 billion worth of projects halted since January 2025	$936 billion to $1.97 trillion over 10 years for all provisions	++
45V H_2 Production Tax Credit (2022)	Up to $3/kg tax credit for 10 years of H_2 production increasing depending on carbon intensity. Construction must start by 2028 instead of 2033 under newly proposed bill.[2] Joint Committee on Taxation (JCT) originally estimated $1.3 billion annually, while some estimates land lower and higher, up to as much as $30.2 billion annually from EPRI[3]	One of the most impactful incentives worldwide making green H_2 produced in the US some of the cheapest worldwide. However, proposed scope reduction risks turning away the many developers that flocked to the US for the tax credit in the first place. Higher risk under the 2025 actions because meeting 45V's hourly matching/additionality/deliverability relies on new renewables	From $13.2 billion over 10 years (JCT) to $756 billion by 2050 (EPRI)	++
45Q CCS Tax Credit (2022)	$180/t$CO_2$ for CCS for blue H_2 and NH_3 for plants beginning construction before 2033. Total expenditure estimates range from $4.3 billion annually (Department of Treasury 2024) to as high as $46.4 billion annually (IEEFA 2025)[4]	Has sparked a windfall of natural gas based new gas value chains, has high staying power as it aligns with the current administration's fossil fuel support agenda. Blue H_2/NH_3 + 45Q becomes comparatively more attractive near-term with new 45V construction start constraints	$43 billion over 10 years (UST) to $835 billion over 18 years (IEEFA)	++
45Z Clean Fuel Production Credit (2022)	Technology-neutral tax credit for low- and zero-carbon transportation fuels produced from 2025 to 2027. Base credit: $0.20/gallon (non-aviation), $0.35/gallon (SAF). Both 5x if labor conditions met. JCT estimate ~$8.4B over the three years.[5] Uncertain outlook beyond 2027	Replaces several fuel credits expiring in 2024. Applies to any transportation fuel emitting ≤ 50 kg CO_2e per MMBtu. Advocacy pieces highlight that much of the forecast outlay could flow to conventional roadway biofuels instead of innovative synthetic or biogenic aviation-based fuels, absent stricter implementation	CATF cites total ~$65.5 billion if modified by Congress[6]	++

[1]Cato Institute [2]Alternative Fuels Data Center: Inflation Reduction Act of 2022 [3]EPRI [4]Taxpayer Costs for CCS [5]The Section 45Z Clean Fuel [6]Clean Air Task Force (CATF)

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

USGC – Summary of New Gas Related Policy

Total costs of tax credits are very open-ended, depending on implementation, supply and demand dynamics, adherence to multipliers and content adders and political stability

Policy	Description	Overall Impact	Incentive	Effect
Infrastructure Investment & Jobs Act (IIJA, 2021)	The IIJA appropriated \$9.5 billion for clean hydrogen, including \$7 billion to establish at least four regional H2Hubs, \$1 billion for demand side support as part of the hubs program, \$1 billion for electrolysis R&D and \$500 million for clean H_2 manufacturing. However, the new administration froze disbursement of many IIJA/IRA grants for H2Hubs in 2025. IIJA also directed DOE to publish a Clean Hydrogen Production Standard (CHPS)	De-risks first commercial projects and creates hydrogen clusters likely producing ammonia or e-fuels for export. Some H2 Hubs potentially in peril due to 45V credit scope shortening and potential direct funding cuts however, complicating offtake contracting and FIDs especially for electrolytic hydrogen. Some OEMs/developers have already reprioritized U.S. projects citing shifting federal policy	\$9.5 billion	++
EPA Power Rule (2024)	In 2024, EPA finalized CO_2 standards for existing coal and new natural-gas units under Clean Air Act §111. Compliance pathways included CCS and, for certain gas units, co-firing with low-GHG H_2. This framework supported demand for CCS (45Q) and low-CI H_2 in the power sector. Trump administration is seeking reversal of compliance regulations currently out for litigation	If the repeal is finalized (and survives court review), the regulatory driver for CCS and H_2 co-firing in the power sector weakens substantially, likely reducing near-term utility demand for clean hydrogen and CCS relative to the 2024 baseline. That pushes more of the hydrogen story back onto industrial, refining, and heavy-transport demand and tax incentives rather than power-sector compliance	N/A (compliance standard)	+
Alternative Fuel Excise Tax Credit (2015/2024)	The IRA also expanded a \$0.50 per gallon equivalent credit for alternative fuels including liquefied gas derived from biomass (bio-LNG) and liquefied hydrogen used as vehicle fuel. Reinstated Dec 31, 2024[3]	Cannot stack this tax credit with other incentives for biodiesel or ethanol. Nevertheless, is helpful for reducing the cost premium associated with liquefying fuels for CNG and future liquid H_2 market	~\$300 million yearly, depends on qualifying gallons	+

[1]Clean Hydrogen Production Standard Guidance | Hydrogen Program

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

USGC – Summary of New Gas Related Policy

Total costs of tax credits are very open-ended, depending on implementation, supply and demand dynamics, adherence to multipliers and content adders and political stability

Policy	Description	Overall Impact	Incentive	Effect
45V Three Pillars (2025)	DOE/Treasury's final 45V rules lock in (i) additionality of new clean power, (ii) regional deliverability, and (iii) hourly matching from Jan 1, 2030 setting a high bar that many projects must redesign around	Uncertainty around these stipulations upon passage of the IRA and European equivalents being developed generated concerns over implementation of tax credits and stifling effect on nascent hydrogen demand as a result of cost increases. Planning new renewables installations in places where interconnections queues are exceeding long such as California and Texas (although fast moving) increases development timelines and levelized costs. However, defenders of the legislation point out the necessary trade-offs for speed and cost for environmental attributes, which have increasing value	N/A	-
Jones Act (1920-2022)	The Merchant Marine Act of 1920, commonly referred to as the Jones Act, regulates maritime commerce in U.S. waters and between U.S. ports (U.S. House of Representatives, 2022). The Jones Act mandates that all goods shipped between U.S. ports must be transported by vessels that are U.S. flagged, owned, crewed, registered, and built	Constraints on domestic marine movements: any coastwise shipment of LNG/alternative fuels (and future NH_3/H_2 bunkering) must use U.S.-built/flag/crewed vessels, a cost and availability hurdle for coastal supply chains especially since there are currently no U.S.-flagged LNG carriers in operation, and the U.S. only has three shipyards capable of building Jones Act-compliant vessels, in contrast with the thousands of shipyards in Japan and China[1]	N/A	-

[1] Clean Hydrogen Production Standard Guidance | Hydrogen Program [2] Final-LNG-as-a-Marine-Fuel-in-the-United-States.pdf

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

USGC – Inflation Reduction Act (IRA) Deep Dive

The IRA aims to make clean technologies the most cost-effective option by driving both supply and demand

2025: The Trump administration has streamlined some of the measures in the One Big Beautiful Bill passed July 2025 followed by an executive order directing Treasury to tighten beginning of construction rules and enforce early terminations for certain clean electricity credits, **constraining new green-power buildouts and complicating compliance with 45V's hourly-matching/additionality for electrolysis**

Updated estimates of the total public expenditure are in the trillions of dollars over the next ten years, many criticize the burden this places on the taxpayer

Stacking of credits is not allowed for single facilities, however different assets can each claim their appropriate credit (e.g. 45Y PTC or 45E ITC for renewables plus 45V for hydrogen production) so long as they're separate property and each meets its own rules

2022: Bipartisan legislation passed under the Biden Administration with an initial total spend estimate of $369 billion over ten years, and updating many existing credits of the Build Back Better Act (2021) and before

Technology	Tax Code	Category	Investment Tax Credit	Production Tax Credit
Non-emitting generation	48E or 45Y	Base	6%	$5/MWh
Non-emitting generation	48E or 45Y	Bonus: Wage & Apprenticeship	+24%	+$22.50/MWh (27.50/MWh)
Non-emitting generation	48E or 45Y	Domestic Cost Adder	+10%	+$2.5/MWh ($30/MW/h)
Hydrogen Production	45V	Base	N/A	$0.60/kg H_2
Hydrogen Production	45V	Bonus: Wage & Apprenticeship	N/A	+$2.4/kg H_2 ($3/kg H_2)
CCS and DAC	45Q	Base	N/A	$17/t$CO_2$ $36/t$CO_2$ DAC
CCS and DAC	45Q	Bonus: Wage & Apprenticeship	N/A	($85/t$CO_2$) ($180/tCO_2 DAC)
Clean Fuels	45Z	Base	N/A	$0.20/gal non-SAF $0.35/gal SAF
Clean Fuels	45Z	Bonus: Wage & Apprenticeship	N/A	($1.00/gal non-SAF) ($1.75/gal SAF)

USGC – IRA 45Q Tax Credit for Carbon Sequestration

45Q availability through beginning of construction by 2033 has not been changed in recent legal updates

2025: Some commentary notes industry lobbying to preserve existing beginning of construction safe harbors amid an executive order pushing for tighter rules. Treasury also issued the 2025 inflation adjustment for 45Q

2022: Passage of the IRA significantly improves the incentive structure for CCS, and stipulates:

- 12-year credit window after equipment is placed in service.
- Inflation adjustment starts in 2027
- Direct pay is available for:
  - Tax-exempt entities: full 12 years
  - For-profit entities: first 5 years
- Transferability: Credits can be sold to third-party taxpayers during the 12-year period
- Cash received from transfers is not taxable income
- Eligibility threshold: Power generation facilities must capture ≥ 75% of produced CO_2
- Construction start deadline: Extended to January 1, 2033

2008: Originally introduced in 2008, expanded in 2018, and significantly enhanced by the IRA in 2022

Key Takeaways:

- IRA passage lowered the threshold for eligibility and increased credit value
- Also extended the credit availability by seven years (to 2033)

The IRA has broadened the definition of eligible facilities

Eligible Facility	2018 BBA Capture Min. (MT CO_2/yr)	2022 IRA Capture Min. (MT CO_2/yr)
Power Generation	500.000	18.750
Industrial	100,000	12,500
DAC	100,000	1,000

The IRA has increased the maximum credit

Eligible Facility	2018 BBA Capture Min. (MT CO_2/yr)	2022 IRA Capture Min. (MT CO_2/yr)
Point Source Stored	50	65
Point Source Utilized	35	60
DAC Stored	50	180
DAC Utilized	35	130

USGC – IRA 45V Tax Credit for Hydrogen Production (1/2)

45V is expected to significantly improve the cost-competitiveness of green H_2-based value chains in the US

2025: In July, the One Big Beautiful Bill passed, limiting the availability of the credit to projects starting before January 1st, 2028, instead of 2033 as originally planned (proposed limiting to 2026 in original proposals)

In January 2025, the US DOE released final regulations for the Section 45V tax credit, accompanied by the release of the 45VH2-GREET Model as the sole model for determining **well-to-gate GHG emissions** for the 45V credit

Media and legal alerts flag heightened uncertainty and potential earlier phase-out pressure via related provisions; projects are rushing to meet construction deadlines

Stacking incentives is possible, especially 48E and 45Y renewable energy used to power electrolyzers. Credits can be claimed for e-fuels, **but cannot be further stacked with 45Z or 45Q**

2022: Inflation Reduction Act passed including the 45V tax credit for clean hydrogen production (valid for ammonia and e-methane production) valued at $13.2 billion over 10 years by the JCT (estimates vary widely)

Key Requirements:

- Must meet the Three Pillars of clean hydrogen production: Incrementality, temporal matching, and deliverability, verified through Energy Attribute Certificates (EACs)
- **Must fulfil prevailing wage and apprenticeship requirements to obtain the full credit**, ensuring adequate wages by region
- This credit applies to production after December 31, 2022, during the 10 years beginning on the date the facility is originally placed in service

Official Guidance of 45V Incentive Allocations by Carbon Intensity

Emissions Threshold Based on LCA (kg CO_{2e}/kg H_2)	Base Tax Credit ($ per kg)	Tax Credit with Prevailing Wages & Apprenticeship Multiplier (5x) ($/kg)
0 – < 0.45	$0.60	$3.00
≥ 0.45 – < 1.5	$0.20	$1.00
≥ 1.5 – < 2.5	$0.15	$0.75
≥ 2.5 – < 4.0	$0.12	$0.60

[1] Federal Register :: Credit for Production of Clean Hydrogen and Energy Credit

USGC – IRA 45V Tax Credit for Hydrogen Production (2/2)

The IRA aligns generally with the Delegated Act principles on clean H_2 production with its "three pillars"

Principles of Incrementality, Temporal Matching, and Deliverability[1]

The final regulations published in January 2025 emphasize the three pillars of **Energy Attribute Certificates (EACs)**, which verify claims to specific energy sources

- **"Incrementality"**: The electricity used to produce clean hydrogen must come from a source beginning operation within 36 months of the H_2 production facility or have received a capacity uprate within the same window. Other options to prove incrementality include electricity from certain merchant nuclear facilities (subject to limits), sources with added CCS technology, and states with qualifying decarbonization standards (currently Washington and California)
- **"Temporal matching":** The regulations require annual matching of EACs until January 1, 2030, after which hourly matching is required. Taxpayers can determine GHG emissions on an hourly basis using eligible EAC attributes
- **"Deliverability":** EACs must come from the defined region corresponding to the balancing authority to which the hydrogen facility and the EAC source are interconnected, with some flexibility for cross-regional delivery if EACs can track transmission and attest no double counting (even allow imports from Canada/Mexico with attestation)

[1] IRC Section 45V Tax Credit: Final Rules Released | Cherry Bekaert

Key Takeaways

- If taxpayers retire EACs for each unit of electricity claimed, a facility's use of grid-connected electricity can be treated as coming from a specific generation facility
- U.S. allows annual matching until 2030, but EU requires monthly between 2027 and 2030. **So hydrogen produced in months with no matching renewable output could fail RFNBO validation even if it meets U.S. criteria**
- Additionally, the U.S. flexibility around cross-regional EACs may not satisfy EU's stricter market-bidding-zone rules. Especially in imports, the **EU may not accept distant or imported attribute certificates as RFNBO-compliant**
- If U.S. producers benefit from state or federal subsidies to their power source (e.g., tax credits or incentives), that electricity may fail EU RFNBO's strict no–state-aid rule
- High electrolyzer utilization could result in full capital cost recovery through the credit

USGC – Infrastructure Investment & Jobs Act (IIJA)

The IIJA was instrumental in setting the groundwork for clean H_2 definition and a national vision for H_2

2025: The new administration froze disbursement of many IIJA/IRA grants. On Apr 15, 2025, a federal judge issued a nationwide preliminary injunction ordering agencies to resume already-awarded funding (separate litigation produced mixed, program-specific stays) **but un-awarded money for H2Hubs remains at risk** pending policy choices and court outcomes

2021: Passage of the IIJA introduces two major funding programs for H_2:

- **H2Hubs program (OCED):** DOE planned up to $7.0 billion for hub awards plus up to $1.0 billion for a demand-side support mechanism (contract-for-difference–style tools, revenue certainty, etc.). Awarded hubs needed to have feedstock, geographic, and end-use diversity, and comply with community benefits requirements (25% of benefits to underserved communities)
- **DOE's Clean Hydrogen Electrolysis Program (HFTO):** $1.0 billion for R&D to cut electrolytic H_2 costs (active; first $750 million tranche announced Mar 13 2024) and $0.5 billion for manufacturing and recycling

Numerous naming conventions (Bipartisan Infrastructure Law most famously) and language iterations cycled through. Clean H_2 definition linked to GHG standard and broadening of existing R&D program feedstocks

Regional Clean Hydrogen Hubs Program Updates:

Reuters reported in Mar 2025 that DOE was considering **reducing or eliminating funding for four hubs:** Midwest, Pacific Northwest, California, and Mid-Atlantic, mostly in democratic states, but to be preserved for hubs in Appalachia, the Gulf Coast, and the upper Midwest, in Republican regions. As of mid-July/August 2025, no final rescission has been completed, but uncertainty remains[1]

In June 2025, DOE's Inspector General found the H2Hubs program lacked required risk assessments and a comprehensive workforce plan, recommending fixes. This raises schedule/management risks for negotiations and awards[2]

The scheme planned to provide up to $1 billion of federal funding and attract $4 to $5 billion in private sector investment to each of the seven hubs. Phase 1 funding of $87.5 million was agreed in September 2024 for the seven selected hubs

[1] US weighs funding cuts [2] Audit

Australia – Overall Assessment of Regulatory Framework

Export-Oriented | Renewables Focused | Reversals: Australia's policy framework is mostly supportive of large-scale production and export of new gases, although almost entirely geared towards hydrogen and ammonia (especially green), **and quite small relative to their large project pipeline and other major exporters**. So far, **no large-scale commercial export projects have reached FID**, but demand side pull from Japan's CfD programme could move some projects through. New gases enjoy bipartisan support, with the new Labour government increasing support for H_2 export, however, there have been instances of **policy reversal at state-levels**

Key Considerations

1. Government support is not necessarily a given. Queensland government **withdrew a $1 billion subsidy commitment** for a flagship green H_2 project near Gladstone and **South Australia scaled back its state-funded electrolyzer plan**[1,2]
2. Pipeline attrition is high in Australia, Several Australian green-H_2/NH_3 ventures, have been scaled back or cancelled in 2024–25 (**Fortescue canceled two projects post-FID**) with developers citing global policy shifts, economics and power costs. The **Safeguard Mechanism is another domestic constraint listed** especially for gas-based routes
3. State EPAs e.g., WA's EPA) and native-title agreements are **decisive gates for mega-projects** (wind/solar/H_2/NH_3), often extending timelines even as WA pushes "green-tape" reforms due to permitting/land & cultural heritage processes

[1]Green hydrogen has stalled in Australia [2]Labor landslide

Major Policies and Impact

H_2 Production Tax Incentive (HTPI)

HPTI directly cuts LCOH by **A$2/kg for qualifying output**; GO certification creates a traceable carbon-intensity label for export buyers

Hydrogen Headstart program

~$2.6 billion expected to significantly de-risk flagship H_2/NH_3 plants intended for export. So far, CIP Murchison (1.5GW H_2 and NH_3 export) and Orica HVHH (green NH_3 retrofit) have received A$814 million and A$432 million respectively

Safeguard Mechanism

Provides an incentive for lowest-CI production facilities, which can trade additional compliance credits. However, hampers gas-based pathways as facilities in scope **lose capacity to monetize voluntary credits** (ACCUs)

ARENA/CEFC/EFA Funding

Targeted grant funding with modest budgets in the low single billions that have supported biomethane injection, e-methane export R&D, SAFs, H_2/NH_3 manufacturing and innovation to de-risk technology implementation

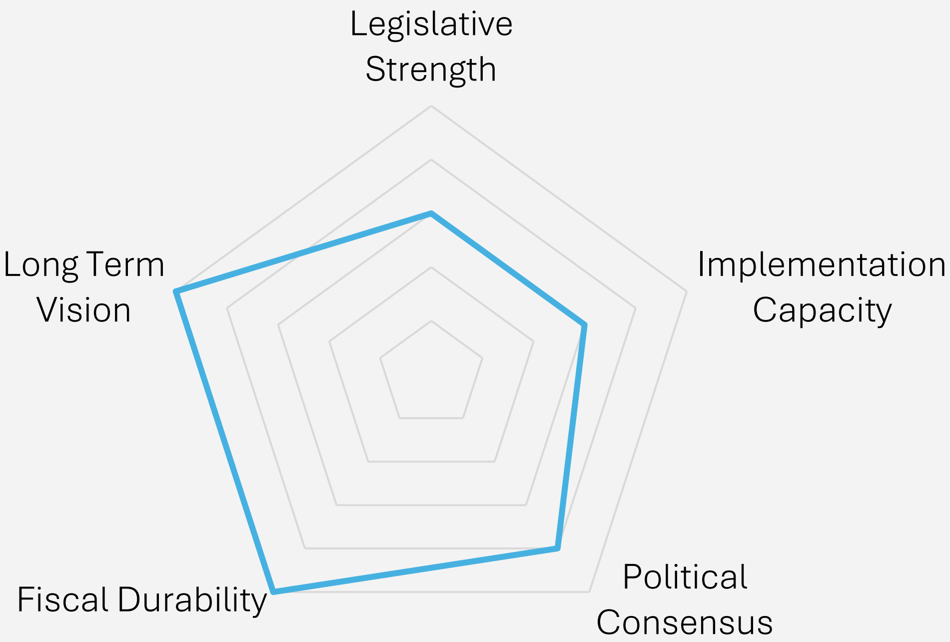
Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive

Australia Regulatory Stability Assessment

The newly elected (May 2025) Australian government is intent on advancing their new gases export push by increasing incentives; political and execution risks are still present however

Ranking Matrix of Regulatory Staying Power

Overall: 20/25



[1] dcceew.gov.au

Legislative Strength

- Recent \$A6.7 billion Hydrogen Production Tax Credit, \$A4 billion "Hydrogen Headstart" program. These initiatives signal strong policy intent and a growing suite of incentives (though still less generous than the U.S. and Middle East)[1]

Implementation Capacity

- Australia has experience with mega-projects (e.g. LNG export terminals) and a skilled workforce, however, many announced projects have struggled with permitting, Indigenous land consultations, or economics, leading to a *"hype cycle" drop* in confidence. Still, the presence of serious developers (CWP, BP, Fortescue, international consortia) and government co-funding of initial projects (e.g. \$814 M to one WA project), however, no large-scale export FIDs yet

Political Consensus

- New gases enjoys bipartisan rhetorical support. The prior government (conservative) launched the 2019 strategy, and the current government (labor) has greatly increased funding. However, there have been instances of policy reversal at state levels

Fiscal Durability

- Reliance on annual budget allocations (for grants) which have been allocating more to new gases. Long-tenor \$2/kg HPTI (law) and Hydrogen Headstart revenue support; strong legal tenor to 2040

Long Term Vision

- Australia has an ambitious long-term target of 15 Mt annual H_2 production by 2050, and many mega projects with decades long planning. However recent shakeups show that despite national strategy, specific project supports can be subject to local politics

Australia – Summary of New Gas Related Policy

Australia has a modest availability of funds available for new gases, with an export and production focus

Policy	Description	Overall Impact	Incentive	Effect
Hydrogen Production Tax Credit (2025)	Tax incentive paying up to $2 per kilogram of renewable hydrogen produced between 2027–28 and 2039–40 for 10 years	HPTI directly cuts LCOH by A$2/kg H_2 for qualifying output; GO certification creates a traceable carbon-intensity label for export buyers. Derivatives such as NH_3 and e-methane should qualify for support, provided criteria are met	$A6.7 billion (~$4.3B) over 10 years	++
Hydrogen Headstart Program (2023)	Total budget of A$4 billion in competitive funding to large renewable hydrogen projects in the form of production revenue support (a form of "contract-for-difference" subsidy) to help producers cover cost premium	In late 2023 the government shortlisted six projects for this funding. Expected to significantly de-risk flagship H_2/NH_3 plants intended for export. So far, CIP Murchison (1.5GW H_2 and NH_3 export) and Orica HVHH (green NH_3 retrofit) have received A$814 million and A$432 million respectively[1,2]	A$4 billion (~$2.6B)	++
National Hydrogen Strategy (2019) and Updated Targets (2024)	Laid out a vision to be a top global exporter of hydrogen by 2030. It established a regulatory roadmap (e.g. safety standards, guarantees of origin) and identified hydrogen export hubs. By 2022–2023, this was bolstered by state partnerships and new targets (e.g. 30% of Australia's exported energy could be hydrogen by 2050)	The strategy itself is not monetary, but it guided subsequent funding and gave industry confidence in Australia's export ambitions. So far, no large-scale commercial export projects have reached FID, but demand side pull from Japan's CfD programme could move some projects through FID	NA	+
National Greenhouse and Energy Reporting rule change (2025)	companies can now use market-based reporting for consumption of biomethane and hydrogen where backed by certificates—creating "book-and-claim" credibility for buyers[4]	Helps domestic demand and contract structures that underpin export projects[3]	NA	+

[1] Murchison Green Hydrogen Project [2] Hunter Valley renewable hydrogen [3] NGER legislation

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

Australia – Summary of New Gas Related Policy

Australia has a modest availability of funds available for new gases, with an export and production focus

Policy	Description	Overall Impact	Incentive	Effect
Safeguard Mechanism (2023)	The Safeguard Mechanism is the Australian Government's policy for reducing emissions at Australia's largest industrial facilities. Facilities have an annual emissions baseline that will fall by 4.9% each year to 2030 (some exemptions for trade-exposed industries like NH_3)[1] However, ACCU credits cannot be obtained for reductions to avoid double-counting. Supports the establishment into law of Australia's goal to reduce GHGs by 43% by 2030 compared to 2005 levels, and reach Net-Zero by 2050	A gas-based NH_3 plant must start very low-CI (i.e., high CO_2 capture rates) or buy compliance units. Although compliance credits can still be traded at values similar to ACCUs, they are still required for compliance and thus weaken the revenue stack compared to using voluntary ACCUs for CCS in blue NH_3 production. However, the mechanism does create a domestic market pull for low-carbon gases, which is expected to drive investment into lowest-CI projects	NA	-
Clean Energy Financing for Hydrogen (ARENA/CEFC)	The Australian Renewable Energy Agency (ARENA) and Clean Energy Finance Corporation (CEFC) have dedicated funds for H_2 and biomethane such as the Future Made in Australia Innovation Fund (FMIA). ARENA provided grants to electrolyzer pilots (A$103 million in 2021 for 3 large projects) and is co-administering Hydrogen Headstart. CEFC offers concessional loans to H_2 infrastructure	These investments promote technology scaling (e.g. domestic electrolyzer manufacturing) and signal government backing for export-oriented projects. Investments from these entities can help reduce barriers to investment by de-risking projects and reducing upfront capital costs. ARENA has provided over $370 million to 65 projects to date	ARENA budget of A$1.9 billion for clean energy innovation, FMIA budget of A$1.7 ($1.1) billion including clean fuels	+
Tax and Royalty Incentives for Clean Fuel Projects	The federal government provides R&D tax credits (up to ~40%) for innovative H_2 production tech. It also enacted fuel tax credits for alternative fuels – e.g. biomethane used in vehicles can be exempt from fuel excise, encouraging bio-LNG trucking	Moderate but helpful economic incentives that complement direct funding. Some states are waiving royalties for green H_2 projects and offering land at concessional rates in renewable energy zones	Variable	+

[1] Safeguard Mechanism – DCCEEW

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

Australia – Hydrogen HeadStart Program

Support for large-scale renewable H_2 and derivative projects serving domestic and international markets

2025: What is the program: Production-credit style grant funding, 10-year revenue support awarded by ARENA via competitive rounds to large renewable-hydrogen projects (including derivatives). Payments bridge the gap between cost and achievable offtake price, paid quarterly in arrears with the value being decided by the commercial gap between the product sale price and cost. Exports are eligible end-uses

Awards so far: CIP's 1.5 GW Murchison project A$814 m (Mar 2025); Orica's Hunter Valley Hydrogen Hub A$432 m (Jul 2025)

2024: A$2 billion more announced May 2024 (total A$4 b) for additional rounds

2023: The Department of Climate Change, Energy, Environment and Water (DCCEEW), in collaboration with the Australian Renewable Energy Agency (ARENA), undertook a design and consultation process for the Program in July 2023

A$2 billion announced May 2023 for Round 1, shortlist Dec 2023

Key Requirements:

- Only greenfield electrolysis projects are considered, powered100% by renewable electricity, with annual REC matching (or behind-the-meter renewables). SMR/blue H_2 is not eligible
- Minimum 50 MW electrolyser (single site)
- Must align with the GO scheme legislated in late 2024, which establishes an internationally aligned certification framework for tracking and verifying emissions for renewable electricity, hydrogen, and eventually clean fuels and green metals
  - Designed to align closely with global markets (International Partnership on Hydrogen Energy), especially emerging standards in the EU, such as those mandated by the Carbon Border Adjustment Mechanism (CBAM), Renewable Energy Directive II and CertifHy (although not yet formally recognized for compliance)
  - Standards are likely to also be accepted by Japan for the purpose of clean fuels supply, as they collaborate closely on certification initiatives

Australia – Hydrogen Production Tax Incentive (HPTI)

Passage of the HPTI under the newly appointed labor government affirms support for clean H_2 and NH_3

2025: Parliament passed the enabling Production Tax Credits law in Feb 2025 (assented 14 Feb 2025); ATO implementation guidance published Feb–Mar 2025

Refundable tax offset of A$2 per kg of eligible renewable hydrogen produced in Australia. Claimable for up to 10 years per project on hydrogen produced between 1 Jul 2027 and 30 Jun 2040. Administered jointly by the ATO and Clean Energy Regulator (CER)

You can combine, but Headstart payments are reduced to the extent you also receive HPTI—i.e., no double-dip windfall. ARENA can receive tax info to administer this

~A$6.7 billion allocated to renewable hydrogen production package for the next 10 years

2024: Announced in the 2024–25 Budget; Treasury consulted on design in June 2024

Key Requirements:

- Hydrogen must be renewable, GO-certified under the new federal Guarantee of Origin (GO) law, with emissions ≤ 0.6 kg CO_2/kg H_2
- If grid power is used, it must meet grid-matching rules set under the GO law
- Companies must comply with forthcoming Community Benefit Principles rules made under the FMIA framework.
- Facilities must reach FID before July 1st, 2030
- Producers must meet Future Made in Australia Community Benefit Principles (jobs, skills, transparency, etc.). Offsets can be reduced if you fail CBP requirements (Treasurer-made rules)

Australia – Safeguard Mechanism

Industry proponents are claiming the new Safeguard Mechanism is cumbersome for CCS projects

Safeguard Mechanism Impact on New Gases

Under the Safeguard Mechanism, new facilities with ≥100,000 tCO_2e/yr get international best-practice emissions-intensity baselines and then face the annual decline rate (generally ~4.9%/yr to 2030)

Additionally, covered facilities can't register ACCU projects to get credits for reductions that occur under their Safeguard baseline (to avoid double-counting). Instead, they earn Safeguard Mechanism Credits (SMCs) only if they beat their baseline. **That removes an ACCU monetization pathway for on-site CCS at a blue ammonia plant and can weaken the revenue stack**

Gas feedstock gets tougher too. As part of the 2023 deal, new gas fields that backfill existing LNG facilities must be treated as "new facilities" with best-practice (effectively net-zero for reservoir CO_2) baselines, i.e., zero baseline allocation for reservoir CO_2. That pushes upstream gas costs (offsets/CCS) feeding blue-ammonia value chains

The default prescribed unit price of SMCs for 2024-25 is A$36.05[1]

[1] Safeguard Mechanism - DCCEEW
[2] Australia's CCS carbon credit pathway to remain limited | Latest Market News

Key Takeaways

- **Abatement cost can often be lower than ACCU prices, nullifying an attractive business case.** However, facilities performing better than their baseline can sell additional SMC credits, which have tracked closely to ACCU prices (A$33.60/$tCO_2e$ - $21.90/$tCO_2e$ July 2025)[2]
- Many green-NH_3 projects (electrolysis + Haber-Bosch) have low direct emissions and may fall below the threshold, in which case the mechanism doesn't apply.
- **Only scope 1 emissions are covered**, so emissions from grid power for low-carbon/blue hydrogen value chains would not be impacted by tightening baseline
- Trade-exposed relief (TEBA) for eligible manufacturers, which can get a **reduced decline rate** (as low as 1% for up to 3 years) to manage competitiveness, **helpful for ammonia exports, but temporary**

Middle East – Overall Assessment of Regulatory Framework

Direct Investment | Evolving | Unconstrained: Leading Middle Eastern producers are pursuing state-driven strategies to become major exporters of hydrogen, ammonia, and e-fuels. Rather than traditional tax incentives, nations such as Saudi Arabia, the UAE, and Oman provide support via **direct government investment, access to inexpensive feedstock and land, and other favorable terms for development**. Most policies are supportive; the few constraints come from external market rules (e.g., EU import criteria), which are not likely to be a problem if planned for as additional dedicated renewables can be built easily, and many international partners are involved in projects. **Demand-side pull is the limiting factor**, which means regions are in **competition with each other for European and East Asian markets**. For that reason, regions like Oman and the UAE are **steadily expanding their incentive structures** for new gases beyond direct investment alone

Key Considerations

1. Middle East governments propel projects through direct ownership and diplomatic agreements. **Saudi Arabia's NEOM** green ammonia venture (50% owned by NEOM/PIF) and **UAE's TA'ZIZ** industrial hub (ADNOC and partners investing in blue ammonia) exemplify this
2. A crucial support in the Gulf is **low-cost feedstock** and infrastructure. Saudi Arabia and UAE have historically subsidized natural gas for domestic industry at low fixed prices, enabling blue H_2/NH_3 at competitive cost (though this fossil fuel subsidy is gradually being rationalized, which may in turn help renewables-based value chains)
3. Monarchies such as Saudi Arabia and the UAE ensure consistency across political cycles – policies are unlikely to change sporadically unless demand materially falls short
4. Overcoming high costs without long-term/operational price support is also a challenge, something these governments are now addressing through new policy tools such as the potential UAE CfD

Major Policies and Impact

Saudi Arabia's Public Investment Fund

Saudi's Sovereign wealth fund is one of the largest in the world with assets upwards of $900 billion, and is crucial for driving Saudi Arabia's Vision 2030 initiative which sees hydrogen as a key diversification measure. Has created an "Energy Supply" company with **$10 billion of capital for green H_2 projects**

UAE H_2 Investment Entities

The UAE has created a $80 billion Low-Carbon Solutions investment platform called XRG within ADNOC, which will accelerate new gas solutions. The pending creation of a **national entity and structured support schemes would foster investor confidence** and **stimulate domestic demand** and **export capabilities**

Hydrom Auctions

Hydrom offers numerous incentives for green H_2 development, including direct investment, land leases, tax holidays and more. **Eight large-scale green H_2 initiatives with the potential to produce 1.38 Mtpa of green H_2 by 2030** have been awarded in two auctions so far. The next auction will feature increased benefits still

UAE Reporting and Carbon Markets

Two separate laws have mandated corporate carbon accountability and push for alignment with international standards, as well as establish a **National Register for Carbon Credits**, enabling the monetization of emissions reductions, which could stimulate new gas investment dependent on uptake

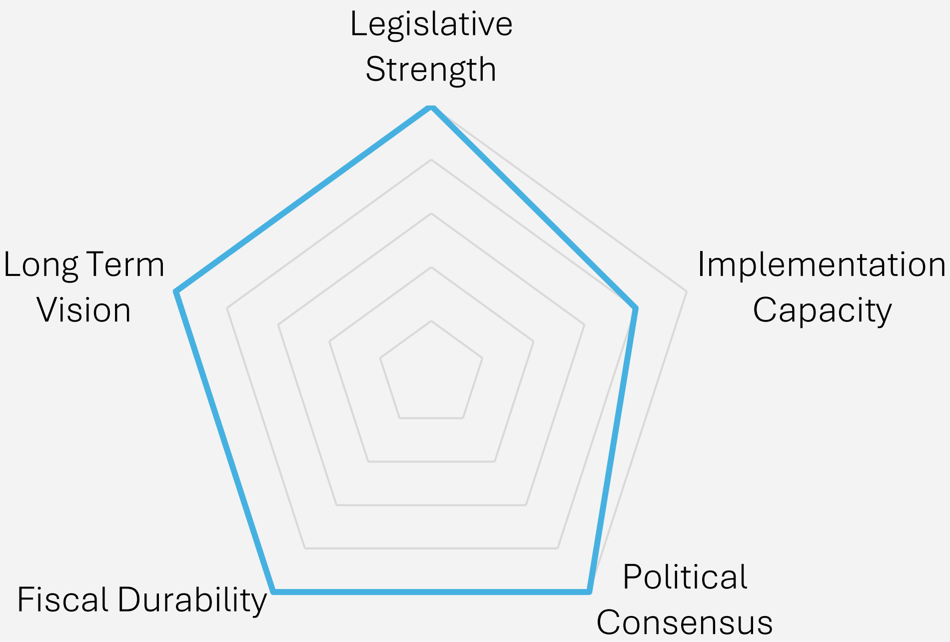
Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive

Middle East Regulatory Stability Assessment

Taken as a whole, governments in Saudi Arabia, Qatar, Oman, and the UAE provide world leading support for new gas projects as it is seen as a strategic priority

Ranking Matrix of Regulatory Staying Power

Overall: 24/25



Legislative Strength

- Gulf states approach new gases through strategic government-led initiatives rather than public legislation, although this is being developed, particularly in the UAE. They provide strong support through the direct backing of state-owned companies (Aramco, ADNOC, Oman's Hydrom), as is "likely even cheaper than subsidized US production"[1]

Implementation Capacity

- Oil and gas exports make up >60% of total exports in Saudi and Qatar, indicating expertise and also a need to diversity. UAE aims for domestic use primarily in the near term, but has low value-added tax rates and tax-advantaged free trade zones.[2] Alignment with EU import requirements could be a barrier for some gases given grid carbon intensity and lack of biogenic CO_2

Political Consensus

- Monarchies such as Saudi Arabia and the UAE ensure consistency across political cycles – policies are unlikely to change sporadically unless demand materially falls short, as leadership is continuous and committed to diversifying investments

Fiscal Durability

- UAE, Saudi Arabia, and Qatar have top sovereign credit ratings, reflecting strong financial stability, low investment risks, and robust economic frameworks, attracting capital for new gas projects

Long Term Vision

- Long-term national strategies with ambitious targets (e.g. Saudi's Vision 2030 includes hydrogen; Oman's 2023 Hydrogen Strategy with competitive auctions)

[1] Middle East eyes global role in green hydrogen trade | S&P Global
[2] Hydrogen Economy Index – ScienceDirect

Middle East – Summary of New Gas Related Policy

Saudi Arabia aims to become a world-leading exporter of green and blue hydrogen, backing projects with direct investment

Policy	Description	Overall Impact	Incentive	Effect
Saudi Arabia's National H_2 Strategy	Saudi Arabia outlined a H_2 strategy (initially in 2020, formal release expected 2023–24) targeting 4 Mtpa of green and blue H_2 in the coming decade, with Saudi Aramco having their own target of 11 Mtpa of blue NH_3 by 2030. PIF governor and Aramco chairman Yasir Al Rumayyan earlier this year, that Saudi Arabia aims to have 15% of 'blue hydrogen' production globally	The government offers low-cost energy (cheap natural gas for blue H_2, vast land for solar) and may provide tax exemptions in new economic zones, greenlighting more mega projects, such as the $8.4 billion NEOM GW green NH_3 export project, than other regions	NA	+
Saudi Arabia's Public Investment Fund (PIF)	Saudi's Sovereign wealth fund is one of the largest in the world with assets upwards of $900 billion, and is crucial for driving Saudi Arabia's Vision 2030 initiative. PIF has created an "Energy Supply" company with $10 billion capital for green hydrogen projects, and have signed numerous MoUs over the years with players such as Korea's Posco, Samsung C&T, and ENGIE (Aug 2025) to develop green H_2 production and export[1]	Direct investment enables mega projects in the country's interests, with essentially no domestic regulatory barriers, though producers face foreign market regulations. Demand side pull will likely be the biggest factor in getting projects off the ground	$10 billion for H_2	++
Saudi Vision 2030	A strategic framework aimed at diversifying the economy and reducing dependence on oil, Saudi Arabia aims to source 50% of its electricity from renewable energy and 50% from natural gas by 2030, to reach net-zero emissions by 2060. It has made significant-scale investments into H_2 as a pillar of technological advancement and diversification under this strategy. Some subsidy reforms have been necessary for achieving their goals, for example, a phase-out of traditional electricity subsidies	Solar uptake in Saudi Arabia has been very fast, largely due to the phasing out of energy subsidies that began in 2018 as part of wider economic reforms and the decreasing cost (and no marginal cost) of solar. This is a driver for renewable gas value chains. The Saudi Industrial Development Fund (SIDF) has also been given a new mandate to invest in energy projects such as hydrogen related to Vision 2030 via mid and long-term loans since 2019	$270 billion for renewables and H_2 to 2030	++

[1]Saudi Press

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

Middle East – Summary of New Gas Related Policy

The UAE has ambitious targets and commercial strength, but lags in real policy development so far

Policy	Description	Overall Impact	Incentive	Effect
UAE National Hydrogen Strategy 2050 (2023)	Aims to become a top-10 producer by 2031, It targets 1.4 Mtpa H_2 by 2031 (green/blue/pink) and ~15 Mtpa by 2050. The strategy contemplates contracts-for-difference, off-take guarantees, and free-zone incentives to attract projects, but as of mid-2025 no new gas dedicated law or incentive programs are in place	The strategy plans to capture a significant international market share, while also integrating hydrogen into domestic industries such as steel, cement and transportation providing a local anchor for offtake. For export, a market of ~0.5 Mtpa clean H_2 is identified by 2031, of which many projects (TA'ZIZ, KEZAD, etc.) aim to fulfil, and pilots for blue NH3 have already been sent to Japan (ADNOC 2024)[1]	NA	+
UAE Investment Programs	The appropriate commercial mechanisms are to be identified in the 2023–2025 action plan, including the establishment of a national hydrogen entity to oversee the implementation and development of these models. The UAE has created a $80 billion Low-Carbon Solutions investment platform called XRG within ADNOC, which will accelerate new gas solutions including low carbon ammonia	A national hydrogen entity and structured support schemes would foster investor confidence and stimulate domestic demand and export capabilities. UAE had the first solar-powered H_2 production facility in the MENA region with investment from a public-private partnership. A collection of solar independent power projects projected to reach a total capacity of 5GW by 2030, driving clean H_2 and NH_3 production	$80 billion for all low-carbon solutions	++
Abu Dhabi Department of Energy's H_2 Policy and Regulatory Framework (2022)	Outlines development of "hydrogen valleys" (geographically integrated hydrogen ecosystems) and "clean energy clusters" (areas with dedicated clean electricity/desalinated water and transmission for hydrogen production/utilization)	These structures are designed to reduce costs, improve coordination, and scale hydrogen activities by co-locating production, supply, and end-use. Essentially, they complement the hydrogen oases concept from the national strategy	NA	++

[1]Understanding hydrogen and CCS in the UAE

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

Middle East – Summary of New Gas Related Policy

The UAE has established reporting standards and carbon markets, leading the region in this regard

Policy	Description	Overall Impact	Incentive	Effect
Federal Decree-Law No. 11 of 2024 on the Reduction of Climate Change Effects	Effective from 30 May 2025, this landmark law is the UAE's first dedicated climate change legislation, applying to all public and private entities, including free zones and small operators. It mandates measurement, tracking, reporting, and management of greenhouse gas emissions, including implementation of mitigation measures such as CCUS. Emphasis is placed on alignment with global standards, with non-compliance potentially resulting in fines ranging from AED 50,000 to AED 2 million, with penalties escalating for repeat offenses	This law institutionalizes corporate accountability and carbon governance, predicted to encourage adoption of low-carbon and renewable gas solutions (e.g., hydrogen, biomethane) and lay the groundwork for a National Carbon Credit Registry/market (via complementary Cabinet Resolution No. 67 of 2024). Ensuring alignment with global standards could strengthen the viability of exports to Europe and Japan through auctions or bilateral trade	NA	+
UAE Cabinet Resolution No. (67) of 2024 – NRCC	Establishes the National Register for Carbon Credits, enabling the issuance, tracking, and trading of carbon credits, with mandatory compliance deadline the 28 June 2025. Entities classified as either 1) Huge Carbon Emissions: Emitting ≥ 0.5 Mtpa CO_2e (Scope 1 & 2), requiring registration with the NRCC or 2) Participating Entities: Emitting <0.5 Mtpa, who may voluntarily register to generate and trade carbon credits. Penalties for non-compliance include fines up to AED 1 million and platform bans	Companies must develop MRV systems, evaluate trading strategies, and integrate decarbonization plans into their operations. This creates a carbon market, enforces regulatory MRV, and opens revenue streams for new gas producers who may trade credits domestically or internationally via SCA-licensed platforms, as long as double counting is avoided. The impact on new gases will depend on market pricing and uptake for credits, which is yet to be established	Voluntary Carbon Credit Monetisation	+

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

Middle East – Summary of New Gas Related Policy

Oman offers highly favorable conditions to new gas exporter developers with a robust set of incentives

Policy	Description	Overall Impact	Incentive	Effect
Oman's Green Hydrogen Strategy (2022)	Oman launched an ambitious strategy to produce green hydrogen for export, led by the state-owned company Hydrom. Oman aims to produce 1-1.5 Mtpa of H_2 by 2030, 3.25 – 3.75 Mtpa of H2 by 2040, and 7.5 – 8.5 Mtpa of H_2 by 2050. Oman will help develop shared infra, incl. electricity transmission, water and H2 pipelines, desalination etc. as well as help coordinate logistics	Incentives equate to hundreds of millions of USD in forgone government revenue per project; Oman also created a $1.3 billion fund for infrastructure (ports, etc.). Oman's incentives are among the world's most concrete for green hydrogen (land, tax, royalty all eased)	NA	+
Oman - Hydrom Auctions (2022)	Hydrom is auctioning huge land blocks (hundreds of km^2) for renewable H_2 projects and offers generous incentives. In August 2025, Oman announced 90% reduction in land lease fees during project development (and further relief at FEED stage), significant royalty reductions in early production years, and 10-year corporate tax holidays for green H_2 developers. Additionally, only a 4% government stake is required in projects (low by regional standards), and Omani authorities streamline permitting via "one-stop" support	This has drawn ~100 registrations to its tenders. The expected private investment is huge, with combined results of the first and second round awarding eight large-scale green H_2 initiatives across Duqm and Dhofar, committed to producing up to 1.38 Mtpa of green H_2 by 2030. Investment commitments for these projects exceed $49 billion[2]. Although it is unclear what Oman's expenditure will be at this stage, they plan on footing the bill for infrastructure including land, new roads, and warehousing	Private sector expected to take on the majority of cost, Omani budget estimated $5-15 billion (10-30%) for the current pipeline	++
Oman - Royal decree RD 10/23 (2023)	First formal legal instrument in Oman to designate land specifically for renewable energy and green hydrogen projects. It creates the legal foundation for the development of the country's green hydrogen sector—designating the framework for land allocation, governance, and auction-based distribution of those lands governed exclusively by Hydrom, barring approval from the Ministry of Energy and Minerals	By empowering Hydrom to oversee competitive land auctions, the decree fosters transparency, fairness, and global investor participation. It balances new auction processes with continuity for pre-existing project agreements, enabling the government to honor prior commitments while transitioning to a more structured system	NA	++

[1] Oman Green Hydrogen Strategy [2] HYDROM

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

Middle East – UAE National Hydrogen Strategy 2050

The UAE's H2 Strategy is very detailed and comprehensive, covering R&D, domestic demand, and export

The strategy includes a set of enablers and strategic mechanisms:

- **Hydrogen oases:** Dedicated clusters for co-located hydrogen production and end-use, with 2 oases by 2031, expanding to 5 by 2050
- **Research & development:** A national R&D centre for hydrogen technologies, aiming for global recognition by 2050
- **Governance & institutions:** A Federal Hydrogen Committee (chaired by the Ministry of Energy Undersecretary), an external Hydrogen Strategy Advisory Council, and various working groups and a Hydrogen Support Committee for project-specific support
- **Incentives:** Supply- and demand-side supports—possibly including carbon pricing, cost-support elements, revenue-support guarantees, and low-interest financing

2023: Formal publication of the hydrogen strategy by the UAE Ministry of Energy and Infrastructure with support from GHD and Fraunhofer to create a fact-based roadmap for the hydrogen economy. It builds on the overarching Energy Strategy 2050 and the "We the UAE 2031" vision, aligning hydrogen ambitions with broader national goals

Key Objectives:

Production targets:

- 1.4 Mtpa of low-carbon H_2 by 2031 (comprising 1 Mtpa green hydrogen, 0.4 Mtpa blue hydrogen)
- 7.5 Mtpa by 2040
- 15 Mtpa by 2050

Domestic demand forecast:

- Estimated at 2.7 Mtpa by 2031
- Another source anticipates 2.1 Mtpa domestic demand plus 0.6 Mtpa export potential by 2031

Decarbonisation targets:

- Reduce emissions in hard-to-abate sectors (e.g., transport, chemicals, metals) by 25 % by 2031, with an ambition of 100 % reduction by 2050

Aiming to set a **market price for clean hydrogen between 2026–2028** to bolster market confidence

[1] National Hydrogen Strategy | The Official Portal of the UAE Government

Middle East – Oman Hydrom Auctions

Oman's Hydrom auctions have been some of the most successful at attracting export projects

2025: Oman's third green hydrogen projects auction round is progressing with strong momentum, offering a land block of up to 300sqkm in Duqm and inviting proposals for projects covering a minimum of 100sqkm. New project value options include the sale of surplus renewable electricity to the national grid, subject to approval

2024: Up to three blocks in Dhofar were set for allocation by end of Q2 2024 as part of the 2nd auction. 4.5 GW wind & solar capacity, ~200 ktpa hydrogen production, with integration to NH_3/derivatives in Salalah Free Zone

2023: First auction awarded two land blocks in Duqm to consortia with a combined target of 0.5Mtpa green H_2 production, over 12 GW of renewable energy capacity, investment exceeding $20 billion, with concessions spanning 47 years (7 years development + 40 years operation)

2022: Established in 2022 but directive of the Sultan, wholly owned by Energy Development Oman (EDO). Placed in charge of:

- Master-planning the green hydrogen sector
- Allocating government-owned land via competitive auction rounds
- Facilitating shared infrastructure, including roads, storage, and logistics
- Promoting investment through regulatory, permitting, utility coordination

Auction history:

Incentives (Especially in Round 3)

- **Land lease fee reductions:** Up to 90% off during development phase, with possible further discounts during FEED (front-end engineering) stage
- **Royalty reductions**, particularly in early years of production
- **Corporate tax exemption** for up to 10 years
- **Additional benefits:**
  - Access to shared infrastructure
  - Stable regulatory framework and logistical advantages

Qualification Requirements

- Bidders must register a Statement of Qualification (SoQ) within the submission window, which, for Round 3, closes on October 31, 2025
- **Encouraged to:**
  - Form consortia, due to scale and complexity of projects
  - Demonstrate capacity to deliver integrated value-chain projects

North Africa – Overall Assessment of Regulatory Framework

Emerging | Export-Oriented | Fragmented: North Africa is moving from memoranda to frameworks, with Morocco and Egypt setting the pace and Algeria, Mauritania, Tunisia, and Libya following. **Policy design is clearly export-led** (ammonia, e-fuels, green steel) and aims to align with EU RED III / RFNBO, and increasingly Japan. Progress is uneven: rules for guarantees of origin, certification, and grid/water access are advancing in places like Morocco but not yet uniform, and **subsidy models rely more on land, tax relief, and multilateral finance than on long-term price support**

Key Considerations

1. **Pipeline H_2 is one of the key opportunities for which North Africa is well positioned.** Cross-border infrastructure corridors such as SouthH_2 are promising but operate on longer timelines than most near-term FIDs
2. Sponsors continue to carry offtake and foreign-exchange risk in the absence of CfD-type instruments
3. Political stability is stronger in Morocco/Egypt than elsewhere; **long-term targets need secondary rules and clear tariff/wheeling regimes to endure**
4. Projects must prove life-cycle emissions and, for exports to the EU, comply with additionality plus temporal and geographic correlation under RFNBO rules, until national guarantees-of-origin registries are operational and interoperable, **certification remains the primary gate to market**

Major Policies and Impact

Morocco Hydrogen Offer

Aim is to transform a diffuse pipeline into six land-allocated, port-coordinated export projects with time-bound study windows, **materially de-risking early development and speeding FIDs** for green NH_3/e-fuels

Morocco Decrees on Self-Production, Guarantees of Origin & ESCOs

A regulatory backbone with smart-metered self-production, **a national GO scheme**, and ESCO contracting, **enabling EU-aligned RFNBO compliance** and cutting settlement/reporting risk without direct subsidies

Egypt Green Hydrogen Incentives Law

Egypt provides fiscal package (**33–55% cash rebate plus broad VAT relief**) that lowers LCOH and **converts SCZone projects into near-term export FIDs.** Slightly restrictive conditions may limit the implementation

Mauritania Green Hydrogen Code

A clear, investor-protective code with licensing, land allocation, tax exemptions, and a one-stop agency (AMHV). Implementation remains slow, but a rules-based regime can unlock giga-scale exports as capacity ramps

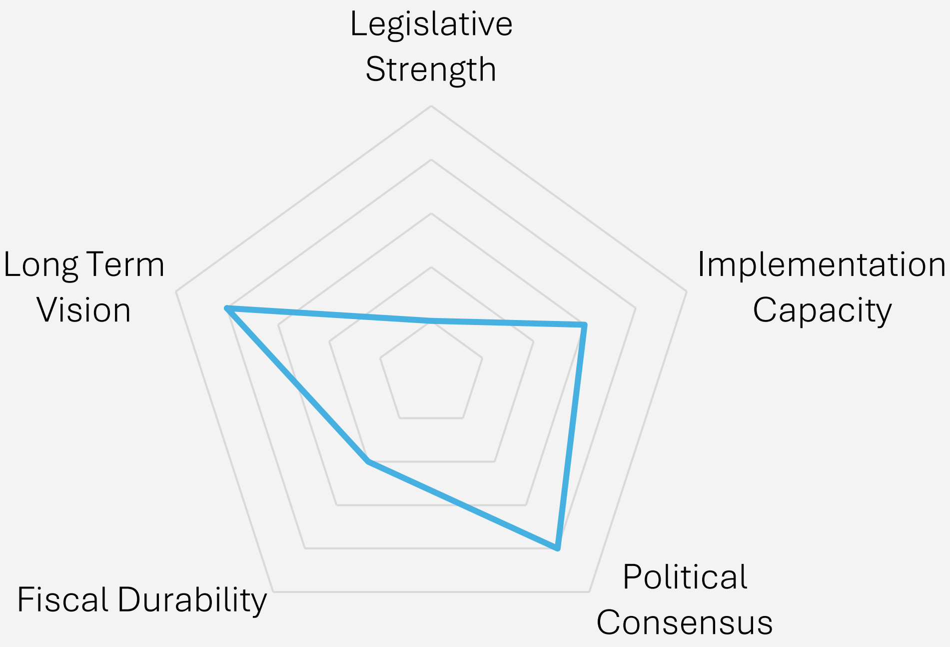
Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive

North Africa Regulatory Stability Assessment

Egypt and Morocco are the most advanced countries in North Africa, but regulatory frameworks must still evolve to ensure projects move from MoU to FID. Both countries rely heavily on Foreign investment and demand

Ranking Matrix of Regulatory Staying Power

Overall: 14/25



Legislative Strength

- Leading countries such as Morocco and Egypt have drafted H_2 strategies and are working on regulatory frameworks (e.g. guarantees of origin for green H_2), but **detailed laws and incentives are not yet fully in place**. Green H2 Morocco grant program of ~$16.6 million

Implementation Capacity

- Both Morocco and Egypt have built large renewable energy projects in recent years (e.g. Morocco's Noor solar park), indicating decent technical capacity and experience working with international developers. Still, **green hydrogen projects are far more complex and will require foreign technology, financing, improvements in infrastructure. Managing water supply for electrolysis is a concern** (North Africa is water-scarce; Morocco and Egypt plan desalination for H_2)[1]

Political Consensus

- **Morocco's monarchy provides stability** and has made renewables/hydrogen a strategic focus, while Egypt's government (though it faces economic turmoil) has consistently promoted itself as a future hydrogen hub. However, governance and bureaucracy can be hurdles; implementation may suffer if there are changes in economic policy or if social pressures divert attention

Fiscal Durability

- **Comparatively week**. Countries cannot bankroll multi-billion projects alone, and **rely on foreign investors in the EU and Gulf**. Egypt is in an IMF program and **faces debt constraints**, meaning it mostly offers tax breaks, land, and regulatory support rather than direct funding. Morocco's government likewise provides some research grants and convening power

Long Term Vision

- Egypt and Morocco see new gases as long-term growth areas, but **do not have fully established roadmaps for achieving their long-term targes** (Egypt announced +$60 B of projects at COP27)

[1] Hydrogen Economy Index – A comparative assessment of the political and economic perspective in the MENA region for a clean hydrogen economy - ScienceDirect

North Africa – Summary of New Gas Related Policy

Morocco attempts to move beyond MoUs with its Hydrogen Offer and enabling decrees make it one of the most advanced export platforms in North Africa

Policy	Description	Overall Impact	Incentive	Effect
Morocco Hydrogen Offer (2024–2025)	National framework allocating public land and fast-tracking 6 export projects (ammonia, synfuels, green steel). On 6 March 2025, the steering committee selected five investors (consortia) for six projects with a combined value of MAD 319 billion (~$35 billion). Each project receives an initial 6-month land-reservation window to complete detailed technical studies. Up to 30,000 ha may be granted per project after preliminary agreement[1]	The offer converts a large, diffuse pipeline into six named projects with land pathways and study timelines, materially improving the chance of bankable FIDs by reducing early-stage uncertainty. With MAD 319 bn at stake and global developers (ACWA, TAQA, CEPSA, CTG, etc.), Morocco is now among the largest emerging export platforms for green molecules in MENA. However, shared-infrastructure timelines are TBD, which can slow FID	Land parcels up to 30,000 ha; 6-month reservation for feasibility studies	++
Morocco Decrees on Self-Production & Guarantees of Origin	Three decrees operationalize Morocco's renewable and hydrogen framework[2] • Decree 2.24.804 regulates self-production of electricity and mandates bi-directional smart meters with remote reading to monitor both grid consumption and RES injection • Decree 2.24.761 establishes a system of Guarantees of Origin (GO) for renewable electricity, designating the Ministry of Energy Transition and Sustainable Development (MTEDD) as the issuing authority • Decree 2.24.153 defines the scope of energy service companies (ESCOs)	The decrees do not create subsidies but provide the regulatory backbone needed for export projects. The GO framework offers verifiable proof of renewable electricity, a prerequisite for compliance with EU RED III rules, while the smart-metering decree reduces settlement risks for industrial self-generators and improves the bankability of green hydrogen projects. The ESCO framework widens the service ecosystem, supporting project execution	NA	++

[1] morocco-selects-five-investors-for-billion-green-hydrogen-projects/
[2] new-decrees-on-energy-auto-production

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

North Africa – Summary of New Gas Related Policy

Egypt is now pushing with strategy and incentives; its national plan and Law 2/2024 turn SCZone projects into bankable opportunities

Policy	Description	Overall Impact	Incentive	Effect
Egypt – National Low-Carbon Hydrogen Strategy (Aug 2024)	Egypt adopted a national strategy positioning itself as a global hub for green hydrogen and derivatives, especially ammonia and methanol. The plan sets out to capture 5–8% of the global hydrogen market by 2040, equivalent to up to 5.8 Mtpa H_2. It builds on >20 pilot MoUs signed in the Suez Canal Economic Zone (SCZone) and integrates renewable expansion, desalination, and export logistics. Backed by international institutions (EBRD, AusDE, others), the strategy links directly to Egypt's role as a maritime and industrial hub	Provides a clear national roadmap with quantitative targets, anchoring investor confidence and aligning SCZone projects with export markets in Europe and Asia. It signals to developers and financiers that Egypt is committed to large-scale hydrogen deployment and willing to support long-term infrastructure. By tying projects to the Suez Canal, it leverages Egypt's global shipping position[1]	NA	+
Egypt – Green Hydrogen Incentives Law (Law No. 2/2024)	Enacted Jan 2024: Establishes a comprehensive incentive framework for green hydrogen and derivative projects, including upstream RES and desalination plants (if ≥95% dedicated to H_2), as well as transport, storage, and distribution infrastructure. It provides legal certainty for investors and forms the fiscal backbone of Egypt's hydrogen hub ambitions, particularly in the Suez Canal Economic Zone	The law grants a cash incentive of 33–55% of income tax paid, exempt from further taxation. Provides VAT exemption on machinery, equipment, inputs and transport vehicles, and 0% VAT on exports.[2] By offering predictable tax relief and VAT exemptions, the law significantly lowers CAPEX/OPEX costs and enhances IRRs. Coupled with Egypt's hydrogen strategy, it positions the SCZone as a global export hub for Europe and Asia	Depends on uptake; cash incentive 33–55% of income tax paid, VAT exemption	++
Egypt – SCZone MoUs & Projects	Since 2022, >20 MoUs signed with pilot projects launched, ongoing 2023–2025, with consortia from Europe, Asia, and the Gulf. Early pilot projects: Fertiglobe's green ammonia facility, as well as partnerships with EDF Renewables, Maersk, Masdar, TotalEnergies[3]	Positions Egypt as a first mover in Africa with tangible project activity rather than only strategic announcements	Land allocation	+

[1] Egypt Hydrogen Strategy [2] OECD-Egypt [3] Egypt – SCZone MoUs & Projects

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

North Africa – Summary of New Gas Related Policy

Algeria's ambition is clear, but progress will stay slow until a full hydrogen regulatory framework, certification, and incentives are in place

Policy	Description	Overall Impact	Incentive	Effect
Algeria – National Hydrogen Strategy	Algeria published its first National Hydrogen Strategy outlining plans to produce 30–40 TWh (~1 Mtpa) of hydrogen annually by 2040, with the aim of covering ~10% of Europe's projected import demand. The strategy emphasizes green hydrogen from solar/wind in the Sahara, complemented by blue hydrogen using natural gas with CCS[1]	The strategy signals Algeria's intent to pivot from hydrocarbons to hydrogen exports, using its solar potential and pipeline infrastructure. If implemented, Algeria could emerge as one of Europe's main hydrogen suppliers. However, progress has been slow: the regulatory framework, certification system, and concrete investment incentives are still being finalized, creating uncertainty for investors	NA	+
Algeria, Tunisia, Libya – SouthH_2 Corridor & Hydrogen Backbone	The SouthH_2 Corridor is a 3,300 km dedicated hydrogen pipeline linking Algeria, Libya, and Tunisia to Italy, Austria, and Germany. Around 65% of the route will repurpose existing natural gas pipelines, while the rest will be new builds. It is designed to carry up to 4 Mtpa of hydrogen per year into Europe. The project is endorsed by TSOs from Italy (Snam), Austria (Gas Connect Austria), Germany (OGE), and Tunisia, and is included in the EU's Projects of Common Interest (PCI) and Projects of Mutual Interest (PMI) lists[2]	Provides North African producers with a direct export route into Europe, solving a critical bottleneck for monetizing large-scale hydrogen production. By anchoring hydrogen in EU infrastructure, the corridor significantly strengthens attractiveness to developers. However, timelines are ambitious: permitting, financing, and technical conversion of gas lines to H_2 must align before 2030	PCI/TEN-E status; EU financing & TSO collaboration	++
Algeria – Taqathy+ Programme (Apr 2025)	Cooperation platform launched by the European Commission and Germany with Algeria, builds on the 2021–2024 Taqathy program and expands scope to industrial capacity and export preparation. Activities include technical assistance, institutional strengthening, and pilot-project facilitation in Algeria	Strengthens Algeria's regulatory capacity and signals EU's long-term partnership, but does not itself deliver large-scale investment. By upgrading institutions and promoting local supply chains, it prepares Algeria to absorb foreign capital once the hydrogen regulatory framework is finalized	€28 million	+

[1]Algeria National Hydrogen Strategy [2]SouthH2 Corridor [3]Taqathy+ programme

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

North Africa – Summary of New Gas Related Policy

Libya, Mauritania, and Tunisia require improvements to their regulatory frameworks to advance projects

Policy	Description	Overall Impact	Incentive	Effect
Mauritania – Green Hydrogen Code (Oct 2024)	The Code establishes a legal framework for developing, producing, and exporting green hydrogen and derivatives. It **clarifies licensing procedures, environmental safeguards, land allocation rules, and investor protections**. It also creates the Mauritanian Agency for Green Hydrogen (AMHV) to act as a one-stop authority for permitting and project oversight	Provides legal clarity and reduces investor risk in a frontier market. By codifying rights and obligations, it **shifts Mauritania from MoU-driven announcements to a rules-based environment**. This has already unlocked new giga-scale projects and **FDI commitments** from European, Gulf, and Asian developers. For example, AMAN, Nour and Megaton Moon projects	Exemptions on VAT and corporate tax	++
Tunisia – H_2vert.TUN & National Strategy (2022–25)	Tunisia, with support from GIZ and the German Federal Ministry for Economic Cooperation and Development (BMZ), launched the H_2vert.TUN project to prepare its national green hydrogen framework. The program supports the Ministry of Industry, Mines, and Energy in drafting a hydrogen strategy, building institutional capacity, and developing pilot initiatives. The national strategy (draft in 2024, final expected 2025) **aims to set targets for green hydrogen production, export corridors** (notably via the SouthH_2 pipeline), **and alignment with EU RED III import rules**	Marks Tunisia's transition from early-stage MoUs to structured policy planning. Tunisia has signed several landmark MoUs with international developers (TE H_2, H_2 Global & ACWA Power). The program provides the **institutional backbone and international technical expertise needed to attract private developers**. However, progress is slower compared to Morocco or Egypt, with Tunisia still finalizing its targets and certification framework	€31 million	+
Libya – H2Global MoU (Aug 2025)	**Libya's eastern authorities signed an MoU with H2Global (Germany) and international investors to explore development of a large-scale green hydrogen and ammonia complex**. The agreement envisions capacity up to 1 Mtpa of hydrogen per year, primarily for export to Europe. The project would integrate solar and wind farms in Libya's desert regions with coastal export infrastructure	Libya's first concrete step toward entering the hydrogen market, leveraging solar potential and coastal access. However, **political division between east and west, weak institutions, and security risks create major uncertainties**. Without a unified national framework, projects remain at risk of delay or cancellation	NA	+

[1] Mauritania [2] Tunisia National Strategy H2 [3] Libya MOU with H2 Global

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

North Africa – Morocco Hydrogen Offer (2024 – 2025)

Morocco's National land-allocation and fast-track program to scale H_2/derivatives export projects

The National "Hydrogen Offer" allocates public land and aims to **compresses pre-FID timelines for export-oriented green hydrogen and derivatives** (ammonia, e-fuels, green steel). The Offer pairs **site access with coordinated port, desalination, and grid planning**

Mar 6, 2025: 5 investors selected for six projects in the southern regions with initial 6-month land reservations; Offer remains open to further proponents

Sept 2024: Enabling decrees on self-production, Guarantees of Origin (GO), and ESCOs issued

Mar 11, 2024: Program announced

A central steering committee shortlists developers using a "scientific and transparent" process, then negotiates preliminary agreements. Land parcels (up to ~30,000 ha per project) are reserved for feasibility and FEED. Long-term concessions follow upon meeting milestones (ESIAs, grid/port interfaces, water plan)

Key Information:

Companies/consortia:

- ACWA Power (green steel)
- TAQA–CEPSA (ammonia/e-fuels)
- Nareva (multi-products)
- ORNX/Ortus–Acciona–Nordex (ammonia)
- UEG–China Three Gorges (ammonia)
- Chbika Project (TE H_2/Copenhagen Infrastructure Partners/A.P. Møller Capital) integrates ~1 GW wind+solar with desalination to produce ~200 kt/yr green ammonia for EU markets.

Pipeline & value:

- 6 projects, MAD 319 billion (~$35 billion) combined

Land & siting:

- >1 Mha national H_2 zones, up to ~30,000 ha/project

North Africa – Morocco Decrees & Guarantees of Origin

Morocco implements traceability and self-generation rules that underpin bankable H_2 supply chains.

In Sept 2024, Morocco approved three decrees that operationalize Law 82-21 (self-production) and Law 13-09 (renewables):

- **Decree 2.24.804 –** Self-production & metering. Mandates bi-directional smart meters with remote reading and auditable import/export kWh for industrial self-generators and electrolyzer PPAs
- **Decree 2.24.761 –** Guarantees of Origin (GO). Creates a renewable-electricity GO scheme and designates MTEDD as the issuing authority, enabling verified provenance for power used in RFNBO supply chains
- **Decree 2.24.153 –** ESCO framework. Recognizes energy-service companies to support efficiency and RES deployment

Together, these rules provide the **certification and metering backbone** for EU-facing molecules. GOs are necessary for provenance and disclosure; full RFNBO eligibility will still require temporal/geographic correlation and life-cycle accounting at the project level

Implementation watch-list:

- Metering integration with ONEE/DSOs
- GO registry & portal go-live, publication of rules for issuance, transfer, cancellation & audit
- Developer guidance on how meter/GO evidence will dovetail with RFNBO correlation & LCA dossiers in project certification packages

Key Information:

Who must comply:

- **Industrial self-generators** (cement, mining, fertilizers/chemicals, steel, data centers) connecting to the grid or wheeling power
- **Hydrogen projects** using RES power either behind-the-meter or via grid/PPA; they need smart-meter data for mass balance and GO documentation
- **Suppliers/aggregators & DSOs/ONEE** who must interface with meters and the GO registry to ensure reliable data flows

Issuing authority:

- MTEDD for renewable-electricity GOs
- National registry and portal to manage issuance / transfer / cancellation

Incentive type:

- Regulatory enabler (no cash). It complements Morocco's Hydrogen Offer and land-allocation process

North Africa – Egypt Green Hydrogen Incentives Law

Egypt enacted a fiscal package that enables SCZone-anchored exports

January 2024: The law was enacted through publication in the Official Gazette, and it applies to projects whose principal agreements are signed within five years of entry into force. It was subsequently integrated into Egypt's National Low-Carbon Hydrogen Strategy, approved in August 2024, which targets **5-8% share of the global hydrogen market by 2040 and an upper-bound production of approximately 5.8 Mtpa of H_2 per year**

What it offers:

- Cash investment incentive: **33–55% of income tax paid (refund/credit), not taxable**
- VAT regime: **0% VAT on exports; VAT exemptions on machinery, equipment, inputs, and project vehicles**
- Scope: Eligible upstream/midstream assets (renewables and desalination) if ≥95% dedicated to GH_2; also transport, storage, distribution
- Eligibility: **≥70% foreign-currency financing, ≥20% local content** (where available), COD ≤5 years from agreement (expansions allowed within 7 years of COD) – slightly restrictive
- Permitting: **Access to Golden Licence for single-window approvals**

Key objectives & figures:

Cost and bankability:

- The law is intended to lower the levelized cost of new gas production and to improve IRRs to a level that enables final investment decisions when compared with peer jurisdictions

Investment scale:

- The combination of the national strategy and the Suez Canal Economic Zone pipeline points to investment needs that exceed $60 billion by 2040, while the publicly announced memoranda indicate potential commitments in the range of $80 to $85 billion over the coming years.
- Forms the fiscal backbone for **>20 MoUs** in the Suez Canal Economic Zone (SCZone), also complements concessional finance and port/logistics integration for EU/Asia exports

Brazil – Overall Assessment of Regulatory Framework

Resource-rich | Export-ambitious | In-transition: Brazil has moved from policy concepts to a federal framework: Law 14.948/2024 defines low-carbon hydrogen, launches the Rehidro tax regime and the SBCH certification system; the PHBC tax-credit program (2028–2032) is advancing; and Combustível do Futuro creates demand for hydrogen-derived fuels. Financing is available through BNDES/Finep, while state-led port hubs (Ceará–Pecém, Port of Açu, Suape) are shaping export platforms. These updates are recent and the system is still maturing however, secondary rules, transmission and water infrastructure, and mutual recognition of certificates will determine the pace to export-grade FIDs

Key Considerations

1. The Brazilian Hydrogen Certification System (SBCH) is **in place as a voluntary system**, yet projects still require detailed rules and mutual recognition to **prove life-cycle emissions and EU-style additionality and correlation**, this remains the primary gate to premium markets
2. Rehidro offers **five years of federal tax suspension and Low-Carbon Hydrogen Development Program (PHBC) proposes BRL-scale credits**, but CfD-type price support is limited, so offtake and FX risk sit largely with project sponsors who are largely European (French, German, Dutch)
3. Export Processing Zone (ZPE) based models (Ceará) and private-port models (Açu) give options, but heterogeneous land terms and local incentives require careful structuring to ensure durability across political cycles

Major Policies and Impact

Hydrogen Legal Framework

Defines low-carbon H_2 (7 kg CO_2e/kg cap), creates Rehidro (five-year PIS/Cofins suspension) and SBCH (voluntary certification), and assigns ANP/ANEEL roles, **delivering legal certainty and near-term cost relief**

PHBC Low-Carbon Hydrogen Development Program

Competitive tax credits up to BRL 18.3 billion ($3.4 billion) across 2028–2032 could **materially lower delivered cost and unlock FIDs** once implementing rules are issued

Combustível do Futuro

Introduces LCA for fuels and mandates SAF blending rising from 1% in 2027 to 10% by 2037, **creating a demand pull for hydrogen-derived e-fuels**

PNH2 National Hydrogen Program

Sets milestone with pilot plants by 2025, cost-competitiveness by 2030, hubs consolidated by 2035 and orients federal R&D and planning

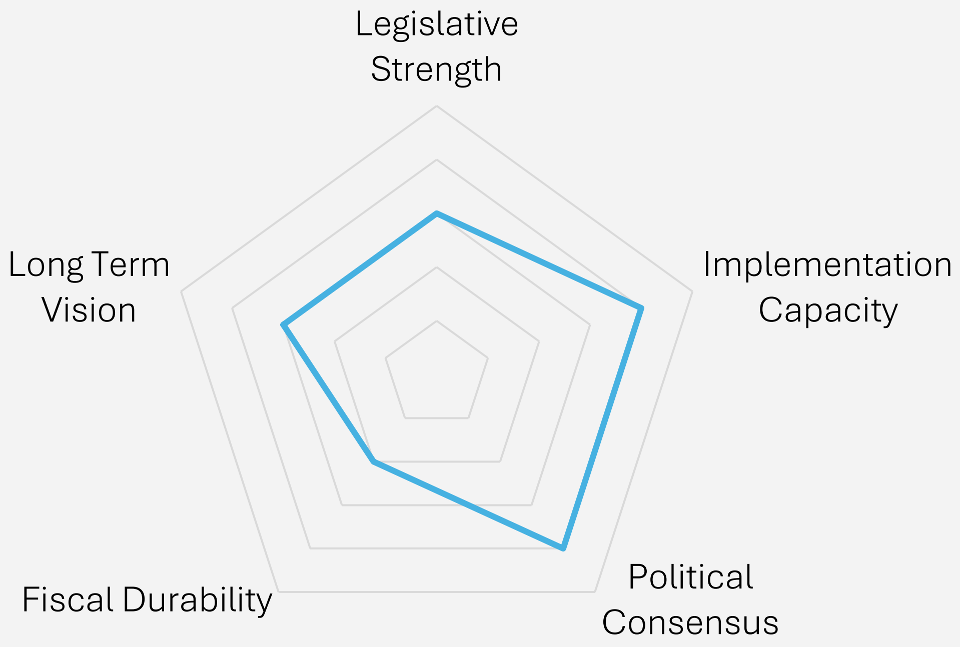
Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive

Brazil Regulatory Stability Assessment

Brazil's clean hydrogen policy is in early stages, is a patchwork of policy support. A comprehensive legislative framework (covering guarantees of origin, tax incentives, etc.) is still under development

Ranking Matrix of Regulatory Staying Power

Overall: 16/25



[1] Brazil unveils multi-billion-dollar support for clean hydrogen industry - Yamna

Legislative Strength

- ~\$3.4 billion in tax credits for H_2 producers, and \$1 billion of public financing for H_2 hubs. State governments especially in the Northeast (Ceará, Pernambuco, Bahia) have introduced local incentives, formed alliances (e.g. Ceará's hub with ports and foreign investors), and streamlined licensing for new gas projects[1]

Implementation Capacity

- Significant capabilities in related sectors (biofuels, hydroelectric dams, offshore oil) and has a strong industrial base interested in consuming clean H_2, more favourable than pure exporters. However, Brazil will need to invest in new infrastructure (e.g. NH_3 export terminals, H_2 pipelines) and improve its sometimes-cumbersome licensing processes to implement projects at scale

Political Consensus

- Previous administration (Bolsonaro) was less focused on green initiatives, though it did start the hydrogen program concept. The current administration (Lula) is prioritizing climate and re-engaging with global green finance. A change in government could swing priorities again. However, many Brazilian states and industry players are independently committed

Fiscal Durability

- New PHBC law caps and staggers credits (2028–32) and additional public finance. Decent legal base, bounded envelope. Likely still to rely heavily on international investment

Long Term Vision

- The government (under President Lula as of 2023) unveiled a National Hydrogen Program and adopted capacity targets (e.g. 6 GW green, 4 GW blue H_2 by 2030). It sees exporting green hydrogen as a way to monetize its renewables, which could entrench support in the long term

Brazil – Summary of New Gas Related Policy

Brazil now pairs incentives and certification with finance and port hubs to enable H_2 exports

Policy	Description	Overall Impact	Incentive	Effect
PNH2 – National Hydrogen Program & 2023–2025 Plan	Brazil's PNH2 sets the federal roadmap for hydrogen, with actions across production, transport, uses, R&D, human capital, and governance. The 2023–2025 plan targets pilot plants by 2025, positions Brazil as one of the most competitive hydrogen producers by 2030, and aims to consolidate hydrogen hubs by 2035. It also signals rising federal support for R&D and demonstration to move projects toward bankability[1]	This plan provides strategic direction and credibility to private developers and state governments. By defining milestones and axes of action, the plan reduces policy uncertainty; however, translating strategy into bankable offtake and certification remains the key execution challenge	R&D funding from ~BRL 29M ($5.3M) in 2020 toward ~BRL 200M ($37M) by 2025	+
Hydrogen Legal Framework – Law 14.948/2024 (Marco Legal do Hidrogênio)	Enacted 2 Aug 2024, effective 1 Jan 2025. This framework establishes the national policy for low-carbon hydrogen, defines categories (low-carbon, renewable, green), and sets a carbon-intensity cap of 7 kg CO_2e per kg H_2 at the policy level. Creates the Rehidro tax regime and the Brazilian Hydrogen Certification System (SBCH) for voluntary certification, and mandates regulation by ANP, with ANEEL support on power-system interfaces[2, 3]	The framework delivers legal certainty and a baseline incentive for early projects while setting up a national certification pathway. The law materially improves Brazil's standing as an export platform but leaves several items for secondary regulation (e.g., SBCH design, mutual recognition with EU/Japan, and detailed Rehidro procedures). However, the carbon intensity cap is more than twice as high as current European and Japanese standards, creating a difference in standards between domestic focused and export projects	Special Incentive Regime for Low-Carbon Hydrogen Production (Rehidro)	++
PHBC – Low-Carbon Hydrogen Development Program (tax credit)	Creates a competitive program of tax credits up to BRL 18.3 billion ($3.4 B) (2028–2032) to stimulate production of low-carbon hydrogen and derivatives. Parts of the original bill were vetoed and are being reworked, but the federal intent to deploy a sizable credit mechanism remains on record[2]	If implemented as proposed, PHBC will materially lower delivered cost and could trigger final investment decisions for large export plants; the policy signal is strong, but timing and design are the main uncertainties until secondary rules are issued	BRL 18.3 bn ($3.4 B) in credits across 2028–2032	++

[1] PNh2 Brazil [2] BakerMcKenzie [3] Marco Legal do Hidrogênio

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

Brazil – Summary of New Gas Related Policy

Brazil now pairs incentives and certification with finance and port hubs to enable H_2 exports

Policy	Description	Overall Impact	Incentive	Effect
Combustível do Futuro – Law 14.993/2024	Enacted 2024 with secondary rules in progress. Brazil establishes a cross-transport decarbonisation package that integrates RenovaBio and introduces life-cycle carbon-intensity management. Creates ProBioQAV (the national SAF program) with ANP oversight and mandates SAF blending that starts at 1% in 2027 and rises to 10% by 2037, creating demand for hydrogen-derived e-fuels[1]	The law drives offtake for hydrogen derivatives in aviation and maritime fuels. Although not a hydrogen-specific subsidy, the law anchors long-term demand, which improves bankability for e-methanol and green ammonia projects	NA	+
BNDES Green Hydrogen Financing Program	Provides long-term loans up to BRL 300 million ($55.3 million) per project, with financing of up to 50% of eligible investment, using Taxa de Longo Prazo (TLP) and Climate Fund resources to reduce cost of capital for pilot and early commercial plants. BNDES has also partnered with the World Bank on transition financing toolkits[2]	The program lowers the weighted average cost of capital for pilot plants and first-of-a-kind assets, improving bankability for export projects located at ports and export processing zones	Loans up to BRL 300M ($55.3M) per project	++
Ceará – Pecém Green Hydrogen Hub (ZPE do Ceará)	The Pecém Export Processing Zone (ZPE) offers twenty-year tax and administrative incentives and has become Brazil's flagship hydrogen hub. In Oct 2024, the federal EPZ council approved Fortescue to invest up to $5 billion on a 121-hectare site, using 1.2 GW of renewables to produce 500 t/day of hydrogen and create 5,000 jobs; cumulative hub investments are guided at $8 billion[3,4]	Positions Ceará as the leading export platform with a clear land, tax, and logistics proposition. Execution depends on grid expansion, desalination, and long-term offtake aligned with EU and Asian certification	ZPE region tax incentives	++

[1] "Fuel of the Future" law [2] BNDES GH2 Program [3] Ceará Green Hydrogen Hub
[4] Fortescue investment to Brazil GH2 project

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

Brazil – Summary of New Gas Related Policy

Brazil's national biomethane program prioritizes domestic decarbonization and creates a strong home-market pull

Policy	Description	Overall Impact	Incentive	Effect
RenovaBio (CBIOs) – National Biofuels Policy	Law 13.576/2017 - RenovaBio creates a compliance market in which fuel distributors must retire a quota of CBIOs each year. Certified producers (including biomethane) generate CBIOs via RenovaCalc and issue them on B3 after eligible sales are recorded. Biomethane is explicitly listed as an eligible biofuel pathway, and the mechanism is designed to evidence emissions reductions in the domestic transport market[1]	CBIOs monetize domestic deliveries, biomethane sold in Brazil earns a compliance premium that export cargoes generally cannot capture, which pulls volumes into the home market and reduces the arbitrage available for bio-LNG/biomethane exports. Export projects must therefore beat the CBIO+local sales value (and logistics advantages) or stack other certificates. In practice, this discourages exports unless foreign buyers pay a clear premium	N/A	-
Combustível do Futuro – National Decarb. Prog, for Natural Gas & Biomethane	Law 14.993/2024 - Establishes a mandatory emissions-reduction program for the gas market by requiring producers and importers of natural gas to cut GHG emissions using biomethane and other eligible actions. CNPE sets annual obligations and ANP regulates MRV, with an initial 1% target in 2026 that may rise up to 10% by the mid-2030s[2]	Creates a domestic compliance value for biomethane that pulls supply into Brazil's gas grid, reducing volumes and arbitrage for exports unless foreign buyers pay a premium above the local obligation value. It therefore supports internal decarbonization while discouraging near-term biomethane/bio-LNG exports but will help bolster domestic new gas production capabilities	N/A	-
ANP Resolutions 886/2022 & 906/2022 – Biomethane Quality & Commercialization	In force since 2022 - Sets technical specifications and quality-control rules for biomethane to be commercialized in the national territory. Res. 886/2022 covers gas from landfills and wastewater plants. Res. 906/2022 covers gas from agro-forestry/agro-industrial and commercial residues, both for vehicular, residential, commercial and industrial use. Standards define composition limits and approval testing for injection or dedicated delivery	By de-risking feedstock quality that can also serve liquefaction, this provides regulatory certainty for domestic injection and sales, facilitating grid and industrial use, however, the focus on national commercialization and the absence of an export-oriented certificate means the rules do not create a clear pathway for export grade bio-LNG/biomethane yet, unless paired with foreign recognition schemes	N/A	+

[1] RenovaBio – Brazil [2] Combustível do Futuro [3] ANP Resolutions

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

Brazil – Hydrogen Legal Framework (Law 14.948/2024)

Brazil's national policy, incentives, and certification pillars for low-carbon hydrogen

Purpose: The law creates Brazil's National Policy for Low-Carbon Hydrogen, embeds it in the National Energy Policy, and promotes technological neutrality, competitive market insertion, predictable regulation, and support for research and development so that Brazil can decarbonize heavy industry and compete in export markets

Definition and emissions threshold: The law defines "low-carbon hydrogen" through a life-cycle assessment approach and adopts a carbon-intensity cap of up to 7 kg CO_2e per kg H_2 for eligibility under the policy. This threshold allows multiple production routes, including renewable electrolysis and qualified low-carbon fuels

Jan 2025: The law enters into effect and establishes the federal policy baseline for low-carbon hydrogen. Follow-on ordinances are being prepared to operationalize incentives and certification
August 2024: The President sanctioned Law 14.948
June 2024: The National Congress approved the hydrogen framework

Governance and institutional roles:

- The National Agency of Petroleum, Natural Gas and Biofuels (ANP) is tasked with authorizing, regulating, and supervising hydrogen activities across the chain
- The National Electric Energy Agency (ANEEL) supports electricity-system interfaces such as grid declarations and metering. The framework anticipates secondary regulation and sandbox tools where needed

Mechanics

Rehidro (Special Incentive Regime)

- Incentive regime created by the law to lower early-stage costs for producers of low-carbon hydrogen and for suppliers of energy and logistics dedicated to the chain
- Suspends PIS/Pasep and Cofins for a period of 5 years per qualified beneficiary within a program window that runs through 2030, and it can apply to domestic purchases or imports of machinery, equipment, and construction materials used in eligible projects

SBCH (Brazilian Hydrogen Certification System)

- A voluntary national certification system that records the emissions intensity and relevant attributes of hydrogen across production, import, storage, distribution, and transport
- ANP will regulate the certification scheme and recognize competent measurement and verification bodies, while secondary rules will set data requirements, system boundaries, auditing, and registry architecture

Brazil – Export Hubs & State-Level Incentives

Port-anchored industrial zones are converting federal policy into export projects

Purpose: The state-led hubs aim to translate Brazil's national hydrogen law and financing tools into bankable export platforms by concentrating land, grid and water infrastructure, certification services, and port logistics in single, investable locations. The purpose is to shorten time-to-export for green ammonia and e-fuels while aligning measurement and verification with the forthcoming national certification system

July 2025: The World Bank and Climate Investment Funds approved approximately $134 million to prepare Pecém's enabling infrastructure
January–March 2025: The Port of Açu expanded its hydrogen corridor with an additional 2,000,000 m^2 and advanced a 1 Mtpa/yr ammonia project toward FID in 2027 and operations in 2030
October 2024: The federal Export Processing Zone council cleared the first large green hydrogen project at Pecém
Since 2021: Coastal states have designated hydrogen precincts around major ports

Mechanics: States pair long-tenor port-land leases and fast-track licensing with federal instruments such as the Export Processing Zone regime, self-production PPAs, and, from 2025 onward, incentives and certification under Law 14.948/2024

State-level hubs details:

Ceará — Pecém (CIPP/ZPE)

- Pecém Industrial and Port Complex, co-owned with the Port of Rotterdam
- Fortescue's 1st phase covers 121 ha, 500 t/day H_2 with capex up to $5 billion and 5,000 jobs expected
- Benefits from 20-year ZPE incentives and, in 2025, secured $134 million of multilateral financing

Rio de Janeiro — Port of Açu

- In early 2025, the port reserved an additional 2,000,000 m^2 (total 3,000,000 m^2 including 1,000,000 m^2 licensed)
- 1 Mt/yr green ammonia plant targeting FID in 2027 and first production in 2030
- Private-port model with phased utilities and marine expansions tied to offtake

Pernambuco — Suape innovation hub

- Technology and pilot-project cluster with BRL $45 million pilots (CTG Brasil) + BRL $18 million innovation call (SENAI/State)
- Workstreams covering production, transport, storage, and measurement and verification for certification

Brazil – RenovaBio (CBIOs) National Biofuels Policy

Brazil's national biofuels policy and compliance credit that pulls biomethane into the domestic market

Purpose: RenovaBio establishes the National Biofuels Policy to reduce greenhouse-gas emissions in the fuel matrix by certifying biofuels, setting annual decarbonization targets for fuel distributors, and creating the CBIO compliance credit that producers issue and distributors must retire

Instruments and how it works: Certified producers and importers generate CBIOs via RenovaCalc after eligible sales are invoiced. The credits are listed and traded on B3, while distributors have individual annual quotas calculated by ANP based on their fossil fuel sales and must retire CBIOs to prove compliance. This design monetizes domestic deliveries of biomethane and other biofuels

Jul 2025: ANP issues a new resolution updating certification procedures for efficient biofuel production, reinforcing program durability
Mar–Apr 2025: ANP publishes the definitive individual targets for 2025 for each distributor, totaling 40,389,998 CBIOs
2023: CNPE Resolution 6/2023 sets decadal targets for 2024–2033 (basis for 2024 national target)
Jun 2019: Decree 9.888 regulates the definition of annual mandatory emission-reduction targets and their allocation
Dec 2017: Law 13.576 creates RenovaBio and its core instruments

Policy details

Governance and institutional roles

- CNPE/MME set national targets and the decadal trajectory
- ANP regulates, certifies producers (RenovaCalc), allocates individual quotas, and verifies compliance
- B3 operates issuance, trading, and retirement of CBIOs
- Certified producers/importers issue CBIOs, and fuel distributors must retire them annually

Targets & latest metrics (most recent official data)[1]

- National target 2025: 40.39 million CBIOs (sum of individual quotas)
- National target 2024: 38.78 million CBIOs; ANP reports 2024 issuance of 42.52 million, 70.82 million CBIOs available (issued+stock), 54.35 million retired by year-end, and an average CBIO price of R$ 87.99, with total traded value R$ 3.9 billion

[1] RenovaBio – Brazil

Chile – Overall Assessment of Regulatory Framework

Ramping Incentives | Export-Oriented | Government Consensus: Chile has a multi-layered policy framework covering high-level strategy, granular action plans, tax incentives, and trade agreements orchestrated to launch a new export industry in green hydrogen and derivatives. Chile has also actively forged international partnerships and regional initiatives (e.g. hydrogen hubs, port expansions) to facilitate future exports of green hydrogen, ammonia, and e-fuels. Chile's government is highly supportive of project development, **granting concessions for infrastructure development (3 alone in 2025 for Magallanes green NH_3 projects) to build missing infrastructure such as port terminals, pipelines, and desalination plants**. Initiatives are also in place to ensure the H_2 boom benefits local communities (Pacto de Magallanes)

Key Considerations

1. Chile was an early mover with a National Green Hydrogen Strategy launched in 2020 (under a center-right government) and updated in 2024 (under a left-of-center government), **showing cross-administration commitment**
2. Challenges remain (e.g. **lengthy permitting, grid upgrades, environmental concerns**), but national and regional policies continue to evolve to address them. Environmental watchdogs ensure projects are not harmful to local ecosysems such as the local whale feeding grounds
3. The government has indicated it will allow **accelerated depreciation and fast write-offs for renewable hydrogen equipment**. It also **opened public financing for shared infrastructure** (power lines, desalination, storage) that benefit multiple H_2 projects
4. Chile participates in regional platforms like H2LAC (Hydrogen Latin America) and has bilateral MoUs with neighbors. Notably, Chile and Argentina are in talks to coordinate on hydrogen corridors – given Patagonia spans both countries, a regional approach to infrastructure (ports, roads, power lines) could benefit both

Major Policies and Impact

Hydrogen Industry Promotion Bill

A set of proposed legislation likely to pass, introducing **H_2 production tax credit auctions** capped at **$2.8 billion, a special tax regime aimed at making Magallanes** the "Saudi Arabia of wind", improved R&D support, and a Green Investment Tax Credit Fund that could offer further tax breaks for new gas producers

Green Hydrogen Action Plan 2023–2030

Highly detailed roadmap fielding 81 specific actions and interim milestones to build a hydrogen industry geared for exports and local decarbonization. Industry leaders particularly praised the plan's focus on speeding up permits, establishing standards, and creating financial incentives

H2 Fund

$1 billion fund made up of 75% loans from multilateral development banks and EU institutions, aiming to unlock **$12.5 billion in private investment in green H_2 and derivatives** by de-risking investments

EU-Chile Advanced Framework

It ensures "H_2 will be able to flow freely across borders" by prohibiting export restrictions like monopolies or special taxes on H_2. Chile is the **first country with which the EU wrote extensive H_2 trade provisions**, smoothing the way for Chilean green H_2/NH_3 to count toward EU targets and move tariff-free

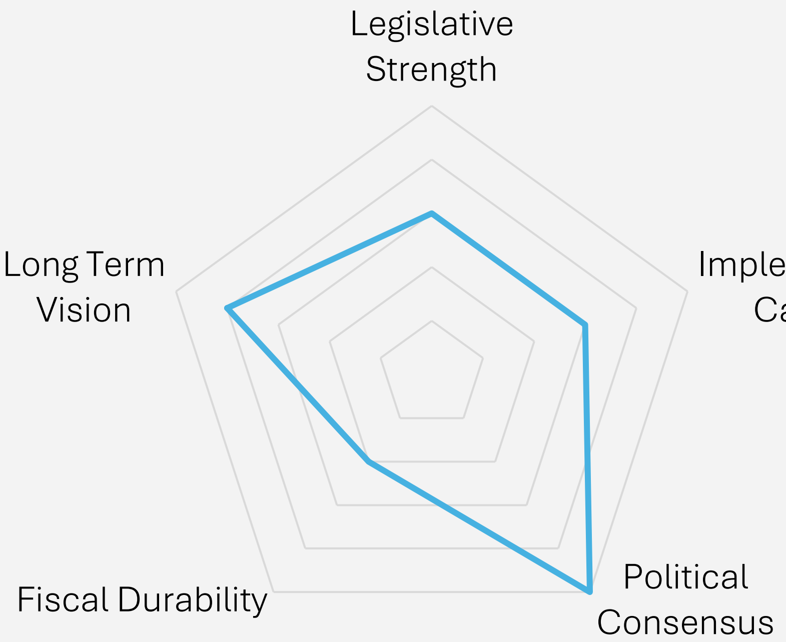
Largely Restrictive | Somewhat Restrictive | Somewhat Conducive | Largely Conducive

Chile Regulatory Stability Assessment

Chile's hydrogen strategy is considered one of the most forward-looking and enjoys broad political support, lending it substantial staying power

Ranking Matrix of Regulatory Staying Power

Overall: 17/25



Legislative Strength

- The government has passed numerous enabling policies. It created a Green Hydrogen Council, allocated $50 M in grants for first mover projects which has stimulated billions in private investment, regulations for guarantees of origin and easing permitting. The recent $2.8 billion tax credit program is designed to move planned mega projects to execution (if passed)[1]

Implementation Capacity

- Chile has a solid track record in deploying clean energy and mining infrastructure. However, new gas projects (especially in Patagonia) are huge and come with new challenges (remote logistics, environmental concerns with extensive wind farms, etc.). Foreign developers (TotalEnergies, Enel, ENGIE, etc.) will lead the buildout in most cases

Political Consensus

- Chile was an early mover with a National Green Hydrogen Strategy launched in 2020 (under a center-right government) and updated in 2024 (under a left-of-center government), showing cross-administration commitment. Specific projects may face local environmental scrutiny

Fiscal Durability

- Chile is also channeling green funds from climate finance sources ($1B World Bank fund, etc.) into new gases but is reliant on foreign investment and is prudent with public investment. Government agencies like CORFO have a mandate to continue funding feasibility studies, workforce training, and infrastructure upgrades (e.g. port improvements in Magallanes)

Long Term Vision

- One of the most forward-looking strategies, aiming to be producing the world's cheapest green hydrogen by the end of the current decade—and to have broken into the top three exporters globally by 2040. However, no targets are established beyond 2040 as of now[2]

[1] Chile Launches $2.8B Hydrogen Tax Credit to Unlock Stalled Projects - Energy News
[2] Chile's bet on green hydrogen

Chile – Summary of New Gas Related Policy

Since 2024, Chile has released highly supportive incentive packages and a detailed roadmap for new gases

Policy	Description	Overall Impact	Incentive	Effect
Hydrogen Industry Promotion Bill (2025)	This comprehensive package is designed to de-risk investments and kickstart a price-competitive export supply by bridging the gap to initial offtakers, with support including H_2 production tax credit auctions for domestic purchasers of green H_2 and derivatives, a special tax regime in the Magallanes region, strengthening of R&D tax incentives, and a new Green Investment Tax Credit Fund	The $2.8 billion incentive is significant for a country Chile's size – it rivals or exceeds many EU countries' hydrogen subsidies especially for demand-side credits. By 2025, several large projects (GW-scale) in Chile are eyeing FID; these incentives could tip them over the line by ensuring a viable offtake price. However, this will likely not directly affect export projects, unless a project is planning for partial domestic and export supply	$2.8 billion	+
Green Hydrogen Action Plan 2023–2030 (2024)	Chile's Ministry of Energy released a detailed roadmap for green H_2 and derivatives in April 2024 detailing 81 specific actions and interim milestones to build a hydrogen industry geared for exports and local decarbonization. Key actions include the launch of the GH2 Facility public-private fund to de-risk projects	Industry leaders particularly praised the plan's focus on speeding up permits, establishing standards, and creating financial incentives. For example, Maria I. Muñoz of H2V Magallanes lauded the plan for setting "the guidelines and conditions that allow the industry's development – defining environmental, social and labor standards, improving permitting, and strengthening critical institutions"[1]	NA	++
National Green Hydrogen Strategy (2020)	Chile aims to produce the world's cheapest green H_2 by 2030 and to become one of the top 3 exporters of H_2, NH_3, and e-fuels globally by 2040. Its strategy is underpinned by having some of the world's strongest solar and wind resources, far eclipsing what it can consume domestically. To kickstart scale, Chile targeted 5 GW of electrolyzer capacity under development by 2025 and 25 GW by 2030, which would translate to millions of Mtpa of new gas exports	The strategy immediately galvanized industry interest. Dozens of green hydrogen projects were announced, with over 50 proposals by 2023 across Chile. Major international developers (Enel, Engie, TotalEren, Shell, CIP, Sumitomo, etc.) partnered with Chilean firms in giga-scale H_2-ammonia projects. These plans explicitly cite Chile's strategy and targets as key drivers. The strategy called for creation of incentives, regulations and infrastructure that have been followed up on in more recent legislature	NA	++

[1]Reportesostenible.cl

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

Chile – Summary of New Gas Related Policy

Since 2024, Chile has released highly supportive incentive packages and a detailed roadmap for new gases

Policy	Description	Overall Impact	Incentive	Effect
H2 Fund (2023)	$1 billion "H2 Fund" backed by loans from CORFO (25%), the World Bank, Inter-American Development Bank, German Development Bank, the EU LATAM investment fund, and European Investment Bank predicted to leverage $12.5 billion in private investment in green H_2 and derivatives	The fund will help mitigate risks, reduce costs, and accelerate green hydrogen projects in Chile for domestic production and export	$1.0 billion	++
Chile-UK Agreement (2024)	Chile partnered with the UK to unlock £5 billion in UK Export Finance credit for Chilean hydrogen projects, explicitly to boost export opportunities and supply chain links with the UK	This partnership seeks to enhance liquidity in Chile's renewable energy sector and create export opportunities for UK cleantech businesses	$6.7 billion (£5.0 billion)	++
EU-Chile Advanced Framework Agreement (2023)	Modernized trade agreement between Chile and the EU (provisionally in force as of Feb 2025) contains a dedicated hydrogen chapter. It ensures "hydrogen will be able to flow freely across borders" by prohibiting export restrictions like monopolies, licensing or special taxes on hydrogen. Chile also agreed to give EU investors equal access to its hydrogen sector (and grids) and to cooperate on harmonizing certification schemes for renewable fuels	In essence, this trade deal cements Chile as a preferred supplier for Europe's future hydrogen needs. Chile is the first country with which the EU wrote extensive hydrogen trade provisions, smoothing the way for Chilean green ammonia/hydrogen to count toward EU targets and move tariff-free	NA	+
National Organic Waste Strategy (2021)	Set targets to raise landfill biogas capture from 5% to 30% – encouraging more feedstock for biomethane. This could eventually have advantages for biogenic CO_2 and e-methane in central Chile where population is highest	A first commercial bio-LNG plant is now under development in Ñuble region (purifying biogas to >99% CH_4 and liquefying it). However, the lack of LNG export infrastructure may mean developments in this sector will be slower to materialize	NA	+

Largely Restrictive	Somewhat Restrictive	Somewhat Conducive	Largely Conducive
- -	-	+	++

Chile – Hydrogen Industry Promotion Bill (proposed)

The proposed piece of legislation would provide key de-risking to Chile's large-scale export initiatives

2025: In August 2025, Chile proposed a bill aimed at spurring domestic and export-oriented H_2 and derivative value chains with tax incentives and special tax regimes. In October 2025, Chile's finance committee has adopted amendments to the draft law, meaning the bill now moves to the full chamber before passing to the senate.

By using auctions, Chile aims to reveal the **minimal subsidy needed, leveraging competition among projects and off-takers**

To spur investment in the remote Magallanes region (Patagonia), which has world-class wind for H_2 but higher logistic costs, the bill offers **generous tax breaks for projects there**. This essentially creates a **low-tax export zone to anchor mega-projects in Magallanes** – an area the strategy pegs as a future export hub. By reducing fiscal burden and upfront costs, Chile hopes to attract the multi-billion-dollar investments (electrolyzers, ammonia plants, ports) needed there

Additionally, Chile's R&D Tax Incentive Law was strengthened: companies now get a 50% credit (up from 35%) on R&D expenditures for sustainable technologies like hydrogen, and the maximum credit was tripled

Key Supportive Elements of the Bill:

H_2 Production Tax Credit Auctions:

- The bill creates a temporary corporate tax credit (against first-category income tax) for domestic purchasers of green H_2 or its derivatives, capped at $2.8 billion
- Allocated via **six competitive tenders from 2025 to 2030**, with higher subsidies in the early years and a declining cap
- Only the first sale from a given H_2 producer qualifies

Magallanes Special Regime:

- Green H_2 and derivative producers in Magallanes would be exempt from corporate income tax, get VAT exemptions on capital goods imports, and still be eligible for H_2 credits
- In exchange, they must contribute to local development (a portion of profits paid to a regional fund)

Green Investment Tax Credit Fund:

- Companies can get tax credits for investing in eligible decarbonization projects with high economic multipliers like new gases – effectively an investment subsidy

[1] Chile proposes USD 2.8bn in tax incentives | Renewables Now

Chile – Green Hydrogen Action Plan 2023-2030

A highly detailed roadmap with a broad range of supporting policies aimed at greatly de-risking new gases

Key Elements of the Roadmap

Plan providing a roadmap of 81 specific actions with 18 priority actions to build a hydrogen industry geared for exports and local decarbonization, including:

- **Financial Facility Opening (Facility GH2):** Launch of a $1 billion public-private fund to de-risk projects, assisting with equipment acquisition, environmental and social risk evaluation system (ESMS), and "green credit" program
- **Public Land Allocation:** A program dubbed "Window to the Future" to auction or lease Chile's vast public lands for green hydrogen projects. The first round for Magallanes land concluded in 2023, awarding prime wind farm sites
- **Streamlined Permitting:** The plan mandates reforms to reduce permitting times by 30%. This includes strengthening environmental and sectoral permitting agencies and publishing standardized environmental baselines for H_2 projects
- **Regulatory Framework Improvements:** New safety standards for hydrogen, rules for seawater desalination use in H_2 production (Action 29), updated land-use regulations to accommodate large H_2 facilities (Action 35), international standards adoption to mirror EU and global standards for hydrogen (Action 23)
- **Domestic Market Creation:** Boost local demand to scale industry. It proposes a **Green Hydrogen Consumption Mandate/ETS** – using an emissions trading system or quotas to require use of green hydrogen or derivatives in domestic refineries, power plants or heavy transport

[1] Microsoft Word - green-hydrogen_action-plan.docx

Key Takeaways

- Industry leaders particularly praised the plan's focus on speeding up permits, establishing standards, and creating financial incentives
- However, developers also urge faster action on key enablers such as bolstering permitting agencies, stimulating hydrogen demand, leveraging existing infrastructure, and creating financing mechanisms
- Implementation of an ETS would boost domestic uptake for new gases as a decarbonization measure, providing much-needed hedging for their export ambitions
- However, without reform of their carbon tax, which is currently limited in scope and size in Chile ($5/t CO_2), an ETS would not be very effective. Reform proposals for a gradual increase have been made but timelines are unclear

Chile – National Green Hydrogen Strategy

Strategy catalyzing both domestic policy follow-through and international commercial interest

Key milestones have been achieved since the launch of the plan, demonstrating Chile's commitment to the sector. Milestones include a fast-tracked piloting approval process, an energy efficiency law allowing FCEVs to count x3 accelerated depreciation, project grants, establishment of a Clean Technologies Institute with $265 for clean energy, etc.

2021: In late 2021, Chile (via development agency CORFO) awarded the first $50 million in grants co-financing 6 pioneering green hydrogen projects across Antofagasta, Valparaíso, Biobío, and Magallanes

2020: Chile unveiled its landmark National Green Hydrogen Strategy in November 2020. This established hydrogen and derivatives as central to Chile's export future. The strategy set bold goals for 2025, 2030, 2040, and beyond and catalyzed a large pipeline of export-oriented projects and international partnerships

2018: Law 21.118 (2018) enabled small renewable and cogeneration producers to inject energy into distribution gridsmdpi.com. Chile's energy mix by 2018 reached ~39% renewablesmdpi.com, though biogas/biomethane remained under 1%

Key Targets:

Chile sees hydrogen and derivatives as a key aspect of economic diversification and the achievement of carbon neutrality goals, setting the following targets:

By 2025:

- 5 GW of electrolysis capacity under development
- 200 ktpa H_2 and derivative production in at least two valleys
- $5 billion investment in H_2 and derivatives

By 2030:

- 25 GW of electrolysis capacity under development
- The cheapest green LCOH costs globally (sub $1.5/kg H_2)
- $15 billion investment in H_2 and derivatives (projected)

The strategy outlines phases: first pilot projects by mid-2020s (with government support), then scaling to large export projects by the 2030s

[1] Energia.gob.cl

Accounting, Certification, and Value Chain Viability

The EU's certification approach is fragmented and complex

How to meet EU regulatory compliance: Use an EU-recognized voluntary scheme to obtain PoS[1] → upload PoS to UDB → qualifies for RED claims, and (for renewable gases) can unlock network tariff discounts via the EU Hydrogen and Decarbonization Package. **Voluntary/corporate claims:** Pair an attribute certificate (AIB/CertifHy GO, ISCC PLUS, etc.) with a robust CI statement (GH2/RSB/ISCC LCA) and a clear chain-of-custody (mass balance or book-&-claim)

Scheme	Jurisdiction	Typical Use Case	Carbon Intensity (CI)	PoS (Proof of Sustainability)	GO / Origin Attribution	Chain of Custody	Elec. Sourcing Rules	Derivatives (NH_3 / e-CH_4)
CertifHy RFNBO[1]	EU-recognized voluntary (Global)	RED Compliance for RFNBOs only	✓	✓	✗	✓ Mass balance	✓ Per RED DA[2]	✓
CertifHy GO (H_2)	EU attribute certificate (Global)	Disclosure/ voluntary claims	⚠ Not full LCA	✗	✓	✓ Book-&-claim	N/A	⚠ H_2 focus
ISCC EU (RFNBO/biofuel)[1]	EU-recognized voluntary (Global)	RED Compliance for all fuels	✓	✓	✗	✓ Mass balance	✓ Per RED DA	✓
AIB EECS GO (gas/H_2)	EU attribute backbone	Disclosure/ energy mix	✗	✗	✓ GO	✓ Book-&-claim	N/A	⚠ Via gas GOs
ERGaR CoO[3] Scheme	EU cross-border CoO hub	RED transport tracking	✗	✗	✓ CoO	✓ Book-&-claim	N/A	✓ RNG and e-CH_4
Union Database (UDB)	EU ledger (compliance)	Cross-border CoO transfers	✗	✓ Records PoS	✗	✓ Mass balance	N/A	⚠ Via schemes
Low-carbon H_2 DA (method)	EU methodology/ threshold	Defines "low-carbon" eligibility	✓ CI threshold	✗	✗	N/A	N/A	✓

[1]The EU relies on a system of Commission-recognized voluntary schemes to certify compliance of fuels with sustainability and GHG criteria. There are 18 approved schemes (e.g. ISCC, RSB, REDcert) used to verify compliance with biofuels/RFNBOs/recycled carbon fuels (RCF) sustainability criteria, and obtain a PoS for RED compliance [2]Delegated Acts [3]Certificate of origin, an "energy attribute" used for voluntary corporate disclosure, similar to a GO, which are slowly replacing them along the AIB scheme for support schemes

Japan's certification approach is relatively underdeveloped

<u>Japan CfD eligibility:</u> Build CI dossier (well-to-gate) that meets Hydrogen Act thresholds → secure METI/JOGMEC Business Plan approval. Third-party global labels (e.g., GH2, ISCC PLUS) can provide support, but government approval remains the gatekeeper. <u>Voluntary/corporate claims:</u> Japan does not yet have a publicly available domestic GO system for hydrogen akin to the EU's, but is intent on developing one. The GX League (a voluntary emissions trading system) could spur this: companies reducing emissions via clean hydrogen might earn extra credit. For now, approvals are centralised via business plans

Scheme	Jurisdiction	Typical Use Case	Carbon Intensity (CI)	PoS (Proof of Sustainability)	GO / Origin Attribution	Chain of Custody	Elec. Sourcing Rules	Derivatives (NH_3 / e-CH_4)
Hydrogen Act "Business Plan" approval (METI/JOGMEC)	Japan – govt approval (CfD gate)	CfD eligibility; imports	✓	✓ Project dossier	✗	✓ Import supply chain MRV	N/A CI outcome-based	✓
Guidelines (CI calc / MRV[1])	Japan – technical guidance	Evidence for approval	✓	✓	✗	✓	N/A	✓
Non-Fossil Value Cert. (power)	Japan – electricity GOs	Power disclosure/retail	✗	✗	✓ Power only	✓ Book-&-claim	N/A	✗
EU/Intl-Recognised Schemes (e.g., IPHE, GH2, ISO)	Favourable – Japan is seeking broad alignment	Voluntary or compliance	⚠ Likely	⚠ Likely	⚠ Likely	⚠ Calling for book-&-claim	N/A	⚠ Likely

[1]Measurement, Reporting, and Verification. Japan is in the process of operationalizing a carbon intensity certification scheme for hydrogen and its derivatives. The government has signaled that it will use "internationally recognized calculation methods" and pursue mutual certification for cross-border hydrogen trade

In practice, this means Japan will likely accept or mirror methods developed by bodies like the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) and standards used by the EU and US. The G7 ministers' meeting in Sapporo (April 2023), chaired by Japan, explicitly endorsed using carbon intensity (CI) metrics instead of color labels for hydrogen. Following that, Japan tightened its draft standards to match the ~70% reduction level of the EU/US

A singular global certification mechanism is unlikely

Global certification standards are plentiful, especially for voluntary markets. However, none are truly universal, as even the certification schemes used for compliance in the EU must still obtain approval from the Japanese government. CORSIA is an exception, as it is already viable in Japan. Multiple efforts are underway to work towards mutual recognition, such as the COP28 Declaration and the IPHE working group on hydrogen GHG accounting

Scheme	Jurisdiction	Typical Use Case	Carbon Intensity (CI)	PoS (Proof of Sustainability)	GO / Origin Attribution	Chain of Custody	Elec. Sourcing Rules	Derivatives (NH_3 / e-CH_4)
ISCC PLUS	Global voluntary[2]	Non-RED markets, B2B claims	✓ PCF option	✓	⚠ (claims)	✓ any	N/A	✓
RSB (global)	Global voluntary[2]	Corporate procurement; multi-feedstock	✓ LCA	✓ robust ESG	⚠	✓ mass balance	N/A	✓
GH2 – Green Hydrogen Standard	Global voluntary[2]	Premium "green H_2" label	✓ <~1 $kgCO_2/kg\ H_2$	✓ ESG safeguards	⚠	✓ project auditing	N/A CI outcome-based	⚠ via H_2-to-derivative rules
TÜV SÜD CMS 70/75	Global voluntary[2]	Corporate labels/PPAs	✓ CI thresholds	✓ scope varies	⚠	✓	N/A	⚠
ISO 14687 / 14067 (methods)	Global standards[2]	Specs & CF accounting	✓ methodology	✗	✗	N/A	N/A	⚠ via LCA scope
IPHE GHG Guidelines	Global methodology[2]	Common CI basis	✓ H_2 LCA	✗	✗	N/A	N/A	⚠ Schemes
CORSIA (RSB/ISCC routes)	Global aviation[2]	Aviation (SAF/e-PtL)	✓ LCA per CORSIA	✓ (SAF rules)	✗	✓	N/A	✓ PtL e-fuels

[1]Product Carbon Footprint, The total GHG emissions associated with making and delivering one unit of a product, expressed in kg CO_2e. [2]Still subject to approval in Japan

Japan vs EU Emissions Accounting Frameworks

Japan's emissions accounting boundaries and carbon intensity (CI) thresholds are more lenient than Europe's, however there is a broad desire to align with the EU's level of rigor inside and outside of Japan[1]

	EU	Japan
Carbon Intensity Threshold	• Hydrogen: **≤ 29.70 kgCO_2e/MMBtu** (≤ 3.38 kg-CO_2/kg-H_2, *70% compared to fossil fuel reference of 94 gCO_2e/MJ*) • Ammonia: **≤ 40.00 kgCO_2e/MMBtu** (~70% reduction from 2,351 gCO_2e/kg NH_3 benchmark value with compliant H_2)[3] • E-Methane: **≤ 29.70 kgCO_2e/MMBtu** (70% reduction for recycled carbon fuels using comparator reference of 94.00 gCO_2e/MJ with compliant H_2)[3]	• Hydrogen: **≤ 29.90 kgCO_2e/MMBtu** (≤ 3.40 kg-CO_2/kg-H_2) • Ammonia: **≤ 49.30 kg CO_2e/MMBtu** (0.87 kg CO_2/kg-NH_3) • E-Methane: **≤ 52.00 kg CO_2e/MMBtu** (~70% reduction from 160.00 gCO2e/MJ benchmark value with compliant H_2) *Intensified thresholds as of June 2024, replacing earlier provisional values and directionally aligning Japan with global standards.* 70% reduction is aimed for within the respective accounting boundaries[2]
Accounting Boundaries	• Hydrogen, ammonia, e-methane: **full lifecycle**	• Hydrogen/Ammonia: **well-to-gate** • E-methane: **full lifecycle**
Emissions Accounting	• **Must be a physical connection for all molecules including H_2, cannot use a book & claim type system**. • Companies can use monthly or quarterly mass balance chain of custody to differentiate blended RFNBOs • Must use recognized voluntary certification schemes (e.g., CertifHy) that issue Proofs of Sustainability (PoS) for emissions accounting • **Does not allow electricity to have achieved financial support**	• The final combustion step is treated as **carbon-neutral** if the **CO_2 was captured and reused once, even if fossil-based** • Must establish agreements to avoid double-counting of emissions • Users of synthetic fuel in Japan should not include emissions already recorded by operators in the country's system
CO_2 Consumption	• The use of fossil CO_2 for recycled carbon fuels are only allowed for electricity production facilities until 2035, and for industry until 2041. Emissions from fuel use are considered avoided, **and still qualify as RFNBOs until this point**; afterwards, **all CO_2 must be biogenic** • Does not allow financial support for CO_2 capture, including CCU credits	• CO_2 for e-methane **does not have to be biogenic under the current framework** as long as carbon intensity threshold is met • Financial support for CO_2 capture is allowed • This could imply **cost reductions on LCOx compared to e-methane destined for Europe**

[1] Japanese Publication (English Version) [2] S&P Global [3] Publications Office

Emissions accounting definitions

The METI in Japan assess imported hydrogen and ammonia on a well-to-gate basis, but signals intention to align with international standards and assess gases on a full lifecycle basis

Well-to-Gate Emissions

"Well-to-gate" emissions refer to **greenhouse gas (GHG) emissions from the extraction of raw materials (e.g., water, electricity, CO_2)** up to the point the **final fuel (e.g., hydrogen, ammonia, e-methane)** leaves the production facility gate. In the METI's definition of well-to-gate, emissions associated with <u>international transportation right up to the import terminal</u> are considered within the boundary, <u>excluding distribution, and end-use combustion.</u>

What it includes:

- Electricity generation
- CO_2 capture (for e-methane or blue H_2/NH_3)
- Synthesis processes ($H_2/NH_3/CH_4$ production)
- Overseas storage
- Compression or liquefaction
- Shipping of the fuel to the import terminal

Full Lifecycle Emissions

"Full lifecycle" or "well-to-wheel" includes **all emissions** from raw **material production through transport, storage, distribution, and final use (combustion)** of the fuel.

What it includes in addition to Well-to-Gate:

- Cracking ammonia (for reconversion to H_2 at import)
- Regasification of e-methane, bio-LNG, H_2
- Distribution to the end-user
- Final combustion or use of fuel (if not offset or recycled)

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CI of Green Ammonia Imports by Region in 2030

New gas supply chain	Production Source	Supply Chain	CI of supply chains beginning in exporting regions ($kgCO_2/MMBtu$)						Destination
			US Gulf Coast	Australia	Middle East	North Africa	Brazil	Chile	
Green Ammonia Reconverted into H_2	Grid	Grid	71.0	69.3	107.8	141.2	14.5	52.7	Japan[1]
Green Ammonia Reconverted into H_2	Grid	Grid	73.4	77.6	113.1	141.9	15.7	56.1	Europe
Green Ammonia Reconverted into H_2	RES	Grid	4.7	2.0	3.3	4.9	5.3	4.7	Japan
Green Ammonia Reconverted into H_2	RES	Grid	7.1	10.3	8.7	5.5	6.5	8.1	Europe
Green Ammonia Reconverted into H_2	RES	RES	4.7	2.0	3.3	0.0	5.3	4.7	Japan
Green Ammonia Reconverted into H_2	RES	RES	4.4	7.6	6.0	2.8	3.8	5.4	Europe

Key takeaways

- All green ammonia produced with renewables and imported into Japan are admissible under the current METI carbon intensity threshold by 2030, whether using grid electricity for the value chain or not as well-to-gate accounting does not account for transport or conversion associated emissions
- The same applies for Europe, as long as renewable power respects Delegated Act rules on additionality, temporal correlation and geographic correlation even for PPAs used along the supply chain except for Brazil whose grid carbon intensity falls below $18gCO_2/MJ$ in the Northeast and other regions
- Grid powered production and value chain far exceed the thresholds for import into Japan and Europe except for in Brazil

[1]Considering the METI definition of well-to-gate emissions, gases sent to Japan only include emissions pre-import terminal

Admissible under current regulatory framework	Not admissible under current regulatory framework
(green)	(orange)

Key regulatory thresholds:

METI Japan: carbon intensity threshold of 29.9 kgCO2/MMBtu well-to-gate for imported hydrogen in this case reconverted from ammonia. Pure imports of ammonia follow a threshold of 49.3 kgCO2/MMBtu

EC EU: full lifecycle threshold of 29.7 kgCO2/MMBtu for H_2 RFNBOs

CI of Blue Ammonia Imports by Region in 2030

New gas supply chain	Production Source	Supply Chain	CI of supply chains beginning in exporting regions ($kgCO_2$/MMBtu) US Gulf Coast	Australia	Middle East	North Africa	Destination
Blue Ammonia Reconverted into H_2[2]	Grid	Grid	35.0	32.0	33.3	43.0	Japan[1]
Blue Ammonia Reconverted into H_2	Grid	Grid	37.4	40.4	38.6	43.6	Europe
Blue Ammonia Reconverted into H_2	RES	Grid	27.7	24.5	21.7	27.9	Japan
Blue Ammonia Reconverted into H_2	RES	Grid	30.0	32.9	27.0	28.5	Europe
Blue Ammonia Reconverted into H_2	RES	RES	27.7	24.5	21.7	23.0	Japan
Blue Ammonia Reconverted into H_2	RES	RES	27.4	30.2	24.3	25.8	Europe

Key takeaways

- All blue ammonia reconverted to H_2 produced with renewables and imported into Japan are admissible under the current METI carbon intensity threshold by 2030 except from the US Gulf Coast and Australia if RES is not used for the value chain or upstream emissions are lower than ~1% (current assumption)
- The Middle East and North Africa are the only countries that can export blue ammonia reconverted to H_2 to Europe under the new Delegated Act on Low-Carbon Hydrogen, requiring a 70% reduction in lifecycle emissions, given proximity of North Africa and low upstream emissions assumed for the Middle East (0.5%)

Admissible under current regulatory framework	Not admissible under current regulatory framework
(green)	(orange)

Key regulatory thresholds:

METI Japan: carbon intensity threshold of 29.9 kgCO2/MMBtu well-to-gate for imported hydrogen in this case reconverted from ammonia. Pure imports of ammonia follow a threshold of 49.3 kgCO2/MMBtu

EC EU: full lifecycle reduction of 70% for low-carbon (blue) H_2, effectively equal to the 29.7 kgCO2/MMBtu used for RFNBOs

[1]Considering the METI definition of well-to-gate emissions, gases sent to Japan only include emissions pre-import terminal
[2]Production of blue ammonia includes emissions from electricity powering CCS

GIIGNL

CI of Piped Hydrogen Imports by Region in 2030

New gas supply chain	Production Source	Supply Chain	CI of supply chains ($kgCO_2/MMBtu$) Middle East	North Africa	Destination
Green H_2 by Pipeline	Grid	Grid	180.2	205.5	Europe
Green H_2 by Pipeline	RES	Grid	33.6	14.1	Europe
Green H_2 by Pipeline	RES	RES	29.6	8.9	Europe
Blue H_2 by Pipeline[1]	Grid	Grid	78.1	74.1	Europe
Blue H_2 by Pipeline	RES	Grid	43.8	29.4	Europe
Blue H_2 by Pipeline	RES	RES	39.9	24.2	Europe

Key takeaways

- Both green and blue H_2 imported by pipeline into Europe from North Africa on average qualifies as an RFNBO or low carbon hydrogen if produced using dedicated renewables or carbon neutral PPAs. **If upstream emissions are greater than 1% however, blue H_2 is not likely to qualify given the 4.9 g CO_2e/MJ threshold**
- Only green H_2 using renewables or carbon neutral PPAs for production and CCS would qualify as RFNBO in Europe, given distance from the middle east (~3,400km) and associated hydrogen leakage and additional energy requirement
- If produced using local grid electricity without PPAs, neither blue or green H_2 piped from the Middle East or North Africa would qualify as RFNBOs or low-carbon hydrogen if imported by pipeline to Europe

Admissible under current regulatory framework	Not admissible under current regulatory framework
(green)	(orange)

Key regulatory thresholds:

EC EU: full lifecycle threshold of 29.7 kgCO2/MMBtu for H_2 RFNBOs

EC EU: full lifecycle reduction of 70% for low-carbon (blue) H_2, effectively equal to the 29.7 kgCO2/MMBtu used for RFNBOs

[1]Production of blue hydrogen includes emissions from electricity powering CCS

CI of Liquefied Green Hydrogen Imports by Region in 2030

New gas supply chain	Production Source	Supply Chain	CI of supply chains beginning in exporting regions ($kgCO_2$/MMBtu) US Gulf Coast	Australia	Middle East	North Africa	Brazil	Chile	Destination
Liquid Green H_2	Grid	Grid	121.7	122.5	188.9	246.1	20.5	89.3	Japan[1]
Liquid Green H_2	Grid	Grid	123.7	126.7	192.0	247.4	22.0	91.6	Europe
Liquid Green H_2	RES	Grid	28.7	28.1	42.3	54.8	7.7	21.9	Japan
Liquid Green H_2	RES	Grid	30.6	32.2	45.4	56.0	9.2	24.2	Europe
Liquid Green H_2	RES	RES	4.0	3.1	3.5	0.0	4.3	4.0	Japan
Liquid Green H_2	RES	RES	5.7	7.0	6.3	5.1	5.5	6.1	Europe

Key takeaways

- Imports of liquefied green H_2 produced with RES is admissible in every country expect the Middle East and North Africa in Japan under the current framework, given high liquification energy draw on domestic grids mostly fossil fuel powered.
- Brazil is the only country with average grid emissions intensity to export liquified green H_2 qualifying as clean hydrogen or RFNBO in Japan and Europe
- Liquified green H_2 produced in 2030 using RES in the US Gulf Coast, Australia, Middle East and North Africa using local grid electricity for the liquefaction would likely not qualify as RFNBO in Europe. Improvements in liquefaction efficiency could make this possible
- The distance between export and import regions makes the energy input requirement and resulting emissions for grid produced liquid green H_2 much larger as boil-off is high

[1]Considering the METI definition of well-to-gate emissions, gases sent to Japan only include emissions pre-import terminal

Admissible under current regulatory framework	Not admissible under current regulatory framework
(green)	(orange)

Key regulatory thresholds:

METI Japan: carbon intensity threshold of 29.9 kgCO2/MMBtu well-to-gate for imported hydrogen.

EC EU: full lifecycle threshold of 29.7 kgCO2/MMBtu for H_2 RFNBOs

CI of Liquefied Blue Hydrogen Imports by Region in 2030

New gas supply chain	Production Source	Supply Chain	CI of supply chains beginning in exporting regions ($kgCO_2$/MMBtu)				Destination
			US Gulf Coast	Australia	Middle East	North Africa	
Liquid Blue H_2	Grid	Grid	51.2	50.2	64.0	84.9	Japan[1]
Liquid Blue H_2	Grid	Grid	53.1	54.3	67.0	86.2	Europe
Liquid Blue H_2	RES	Grid	44.0	42.9	52.6	70.0	Japan
Liquid Blue H_2	RES	Grid	45.9	47.0	55.6	71.3	Europe
Liquid Blue H_2	RES	RES	19.3	17.9	13.8	15.3	Japan
Liquid Blue H_2	RES	RES	21.0	21.8	16.6	20.4	Europe

Key takeaways

- Liquid blue H_2 imports produced with grid powered CCS is much less carbon intensive than liquid green H_2 produced with grid electricity, however none would be admissible in either Europe or Japan
- Only fully RES powered production and value chains would be below carbon intensity thresholds in Japan and Europe.
- Liquid blue H_2 is not likely to be traded expect potentially between Australia and Japan or maybe the Middle East and Japan as costs are prohibitive

Admissible under current regulatory framework	Not admissible under current regulatory framework

Key regulatory thresholds:

METI Japan: carbon intensity threshold of 29.9 kgCO2/MMBtu well-to-gate for imported hydrogen

EC EU: full lifecycle reduction of 70% for low-carbon (blue) H_2, effectively equal to the 29.7 kgCO2/MMBtu used for RFNBOs

[1]Considering the METI definition of well-to-gate emissions, gases sent to Japan only include emissions pre-import terminal
[2]Production of blue ammonia includes emissions from electricity powering CCS

CI of E-Methane Imports by Region in 2030

New gas supply chain	Production Source	Supply Chain	CI of supply chains beginning in exporting regions ($kgCO_2/MMBtu$)						Destination
			US Gulf Coast	Australia	Middle East	North Africa	Brazil	Chile	
E-Methane	Grid	Grid	140.2	141.0	217.5	283.3	23.8	102.9	Japan
E-Methane	Grid	Grid	138.6	142.1	217.2	280.8	21.6	101.7	Europe
E-Methane	RES	Grid	10.9	9.7	13.7	17.3	6.0	9.2	Japan
E-Methane	RES	Grid	9.2	10.8	13.4	14.9	3.8	8.0	Europe
E-Methane	RES	RES	4.2	3.0	3.6	4.3	4.5	4.2	Japan
E-Methane	RES	RES	3.1	4.6	3.9	2.4	2.9	3.6	Europe

Key takeaways

- E-methane produced with RES is admissible in Japan and Europe no matter where it is produced even if grid electricity is used, as minimal electricity is required to power equipment such as compressors and liquefaction compared to hydrogen value chains
- E-methane produced with grid electricity however, is highly carbon intensive due to the low overall efficiency in 2030 (52%) expected to improve greatly as economies of scale are achieved

Admissible under current regulatory framework	Not admissible under current regulatory framework
(green)	(red)

Key regulatory thresholds:

METI Japan: carbon intensity threshold of 52.0 kgCO2/MMBtu imported e-methane calculated across the full lifecycle

EC EU: full lifecycle threshold of 29.7 kgCO2/MMBtu for e-methane

Thank you

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