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Unlocking the Potential of Liquid Hydrogen Supply Chains

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Abstract

As the energy transition progresses, the demand for new energy products such as lower-carbon[1] hydrogen is expected to rise. Global efforts are underway to develop the technology to produce, transport and supply liquid hydrogen (LH_2) to meet the pace, scale and needs of customers as they determine their decarbonisation pathways. However, uncertainties remain regarding the technical and economic feasibility of developing LH_2 export/import at energy system (Giga Watt equivalent) scale. To reduce uncertainty and unlock success, the nascent LH_2 industry, governments and regulators must collaborate on bringing supply, demand, investment and regulations together.

In response to these challenges Woodside Energy and Shell are undertaking a joint program, PROPELH2, with the objective to align the industry on an efficient and safe integration of the LH_2 supply chain, to determine the key levers for cost reduction, to understand the technical feasibility, and propose performance requirements for technology development. In this paper a high-level overview of the gained insights is provided, with the intent to raise awareness, receive feedback, and build momentum.

Collaborations with Air Liquide, CB&I and HD Korea Shipping and Offshore Engineering (HD KSOE) have provided key expertise and inputs for the techno-economic assessments of the LH_2 supply chain, as well as line-of-sight to the development of large-scale hydrogen liquefaction trains (~250 tpd – 500 tpd), large LH_2 storage (40,000-100,000 m^3) and right-sized (60,000-80,000 m^3) LH_2 ships respectively.

Economy of scale proved to be the key lever to reduce the levelised cost of hydrogen (LCOH) for LH_2 export/import, which the paper concludes can only be fully unlocked by development of the required large-scale technology. The cost estimate for “transporting” hydrogen via the LH_2 vector, calculated using the modelling approach described in this paper, is in the range of US$2-4 per kgH_2 (US$18-35 per MMBtu based on lower heating value (LHV), excluding tax). This estimate may be realised when facility capacities of 500-1000 tpd are reached. The estimate includes liquefaction, storage and loading at the export terminal, shipping, as well as boil-off gas (BOG) management, storage and unloading at the import terminal.

Adding the cost for hydrogen produced from natural gas and decarbonised via carbon capture, transport and storage, the LCOH of LH_2 could be in the range of US$4-6 per kgH_2 (US$35-53 per MMBtu based on LHV, excluding tax), meeting a carbon intensity (CI) of <3.4 $kgCO_2/kgH_2$. The CI is broadly aligned with emerging regulatory and market expectations for lower-carbon[1] hydrogen in several jurisdictions such as Japan and Europe.

This outcome has the potential to be feasible across a range of regional and international supply routes, using input assumptions and design parameters that are broadly credible and technically achievable.

Introduction

As the energy transition progresses, global demand for hydrogen is projected to rise. The IEA's ''*Net Zero by 2050''* roadmap [Ref. 1] estimates that hydrogen demand should exceed 150 Mtpa by 2030, with hydrogen and hydrogen-based fuels potentially accounting for 10% of global energy consumption by 2050. The demand for lower-carbon[1] hydrogen is expected to replace fossil-based hydrogen and meet new demand in hard-to-abate sectors like heavy-duty transport and steel production. Even under conservative scenarios, demand for lower-carbon hydrogen could increase tenfold by 2030 [Ref. 2].

While early supply is expected to rely on gaseous hydrogen and ammonia, liquid hydrogen (LH_2) offers potential advantages such as improved density compared to gaseous hydrogen, smaller import terminal footprint, lower product processing energy at import destination, non-toxicity, and high purity compared to ammonia as a vector for hydrogen molecules.

LH_2 supply chains at energy-system (Giga Watt) scale could play a critical role in supporting decarbonisation pathways. Global efforts are underway to develop LH_2 infrastructure, including demonstration projects in Japan and South Korea, novel storage solutions in the U.S., and supportive policy frameworks such as Japan's Contract for Difference (CfD) scheme and the EU's Renewable Energy Directive (RED III) and Carbon Border Adjustment Mechanism (CBAM). However, uncertainties remain around the technical and economic feasibility of scaling LH_2 to meet demand. Despite existing small-scale industry experience, derived from operations since the 1950s, clearer market signals and cost visibility are needed to drive investment in larger-scale supply technologies and end-user adoption.

Overcoming these challenges to unlock the potential of LH_2 will require strong collaboration between supply developers, technology providers, end users, and demand aggregators. In response, Woodside Energy and Shell have launched the PROPELH2 program to define and enable a large-scale, lower-carbon[1] LH_2 supply chain. This program uses techno-economic modelling to identify competitive large-scale LH_2 supply chain configurations, establish key performance and interface requirements, identify barriers to success, and stimulate focused technology development.

The program work to date has leveraged industry-leading data, public sources and LNG supply chain experience to define and model the system. Collaborations with Air Liquide, CB&I and HD Korean Shipping and Offshore Engineering (HD KSOE) have provided critical input on performance and technology

[1] "Lower-carbon" is used to describe the characteristic of having lower levels of associated potential greenhouse gas (GHG) emissions when compared to historical and/or current conventions or analogues, for example relating to an otherwise similar resource, process, production facility, product or service, or activity.

development, as well as insights relevant to techno-economic assessment, for liquefaction, storage and shipping respectively. Collaboration with Air Liquide has also enabled enhanced development of techno-economic models and exploration of novel BOG management solutions. This paper presents key insights from PROPELH2, including techno-economic results, technology considerations, and recommendations for enabling large-scale LH_2 supply chains. The findings aim to support continued collaboration and inform stakeholders across the supply chain.

Supply Chain Assessment Methodology

Modelling scope

The modelling scope includes both gaseous hydrogen (GH_2) production, and the LH_2 supply chain (Figure 1). However, the focus of the paper is on the LH_2 supply chain, which includes hydrogen liquefaction, LH_2 storage, loading and BOG compression at the export terminal, shipping and unloading, and storage and regasification at the import terminal. More details are provided in the sections below.

The distribution of hydrogen from the import terminal to the end-use customers is excluded from the modelling scope (e.g. GH_2 pipelines, LH_2 ship bunkering facilities, truck loading facilities).

Unless otherwise noted, the results shared in this paper are based on hydrogen production from natural gas (NG) via auto thermal reforming (ATR) and decarbonised with carbon capture and storage (CCS). However, many key insights are generally applicable to the renewable LH_2 supply chain as well, where hydrogen is produced via electrolysis powered by renewable electricity. A comparative assessment of renewable LH_2 supply chains is presented.

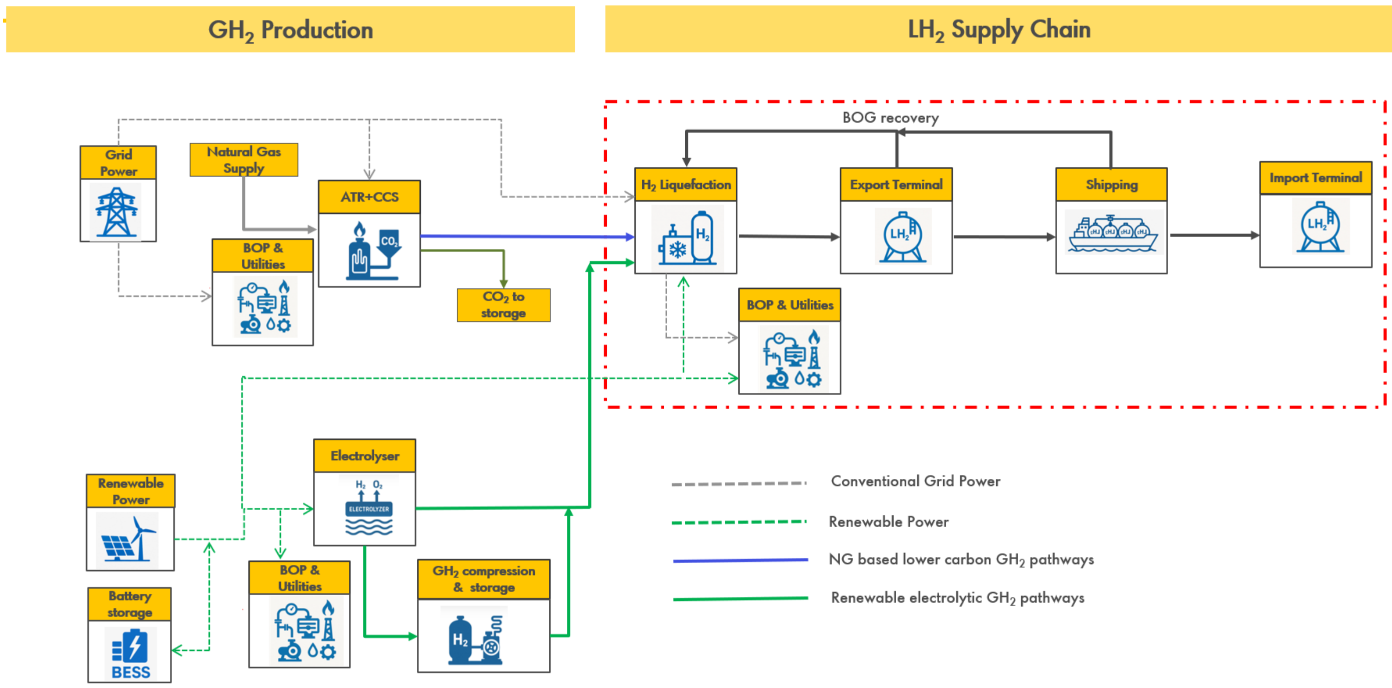

Figure 1 Liquid Hydrogen Evaluation Scope (symbols generated by AI). BOP refers to balance of plant.

Modelling approach

Four models were used to simulate different supply chain configurations, as described below. Shell and Woodside separately developed their modelling methodologies, which were calibrated through input parameter alignment and result comparison. Benchmarking was performed across multiple supply chain configurations to validate consistency between models.

- **BOG integration model**: This is a heat and material balance model that calculates the temperature, pressure and phase change (BOG generation) along the supply chain. It accounts for heat ingress from LH_2 storage and LH_2 piping, energy dissipation of pump power, and the energy release related to the natural conversion of residual Ortho-H_2 to Para-H_2 [Ref. 24] in the storage tanks.
- **Shipping model**: This is a spreadsheet model that calculates indicative costs and carbon intensities for different LH_2 shipping scenarios. Inputs include annualised delivery cargos, ship size, ship speed, distance travelled, assumed ship CAPEX and OPEX costs, and natural LH_2 boil off rates.
- **LCOH spreadsheet model**: For non-intermittent power and NG derived lower-carbon[1] hydrogen supply chains module sizing, LCOH and CI calculations are performed using a spreadsheet on a steady state basis. The model assumes ATR technology, although alternative technologies including partial oxidation (POX) and steam methane reforming (SMR) are mature and could yield comparable supply chain costs.
- **LCOH linear programming model**: This model optimises the LH_2 supply chains for renewable hydrogen (hydrogen produced via electrolysis powered by renewable electricity), when renewable power and hydrogen production are intermittent. It minimises LCOH for a specified annual supply at the outlet of the import terminal, based on a defined renewable profile. The optimisation scope is limited to the sizing of the solar and wind farms, the electrolyser, GH_2 storage (including pipeline storage capacity), battery storage, and hydrogen liquefaction unit. Hourly wind and solar profiles are an important input to this model.

LCOH and CI calculation

The LCOH is calculated using an annualised cost approach, converting capital expenditures into equivalent annual payments over the project lifetime. This method combines annualised CAPEX with annual OPEX (Fixed and Variable), and divides the total by the annual LH_2 quantity delivered to the import terminal (de-rated using a Reliability Availability Uptime (RAU) factor):

LCOH = (Annualised CAPEX + Annual Fixed and Variable OPEX) / (Annual LH_2 delivered to import terminal)

Where:

*Annualized CAPEX = CAPEX * CRF (Capital Recovery Factor)*

The CRF is determined by running a discounted cashflow and production model, using the economic parameters in Table 1. For this analysis, the CRF is 10.4% (excluding tax considerations).

The CAPEX represents total installed cost, including installation cost, owner's costs and contingencies typical for early phase project economics. Fixed OPEX values are estimated as a percentage of the associated CAPEX components. Variable OPEX is calculated separately and includes electricity, natural gas, and carbon dioxide (CO_2) transport and storage costs.

The levelized CI calculation includes direct greenhouse gas[2] (GHG) emissions and indirect GHG emissions associated with natural gas and electricity supply under normal operations. GHG emissions associated with capital goods, i.e., the embodied emissions from the production of purchased fixed assets, plant, property, and equipment, as well as GHG emissions from start-up, shutdown, and upset conditions are excluded from the calculation.

In this study, direct GHG emissions include direct CO_2 emissions from hydrogen production and CCS, and CO_2 emissions from the shipping fuel. Indirect GHG emissions include the upstream carbon intensity of the natural gas consumed, and the carbon intensity of the electricity consumed.

Different jurisdictions have different carbon intensity definitions and targets which also evolve over time. A LH_2 product CI <3.4 $kgCO_2/kgH_2$ is broadly aligned with values proposed in emerging policies such as Japan's Basic Hydrogen Strategy [Ref. 3] and European Directives and Regulations [Ref. 4, 5] to qualify hydrogen as "lower-carbon", thereby potentially enabling access to policy incentives, offtake agreements, and certification schemes.

[2] The seven greenhouse gases listed in the Kyoto Protocol are: carbon dioxide (CO_2); methane (CH_4); nitrous oxide (N_2O); hydrofluorocarbons (HFCs); nitrogen trifluoride (NF_3); perfluorocarbons (PFCs); and sulphur hexafluoride (SF_6).

Economic parameters

PROPELH2 economic input parameters listed in Table 1 were selected to enable comparison of the modelling results with other public assessments. Tax, port fees, and other potential charges have been excluded to maintain general applicability.

Table 1 Economic parameters applied to all modelling results

Parameter	Value	Comment
Internal Rate of Return (IRR)	10%	
Project Lifetime	25 years	
Construction Time	4 years	
CAPEX Phasing	20%, 30%, 30%, 20%	CAPEX phased over 4 years of Construction Time
Tax	0	Excluded for general applicability
Inflation	2%	2% per year
Capital Recovery Factor	10.4%	
Reliability and Availability Uptime (RAU)	95%	Across the full LH_2 supply chain

Data sources, quality and uncertainty

As part of the PROPELH2 program, independent collaborations were established with three key market players. This allowed the modelling to include input parameters (proprietary information) reflecting the latest technological developments and insights. These inputs covered scale, efficiency, and insights relevant to the techno-economic assessment for key technology blocks in the LH_2 supply chain:

- **Air Liquide - Air separation, auto-thermal reforming and cryogenic carbon capture, and H_2 Liquefaction.**
- **HD-KSOE - LH_2 shipping.**
- **CB&I - LH_2 storage tanks.**

Public sources were used for the remaining input parameters.

Most of the CAPEX estimates are Class V, as defined in AACE International Recommended Practice 17R-97 [Ref. 6], reflecting the early stage of project definition. For the sensitivity analysis, a corresponding CAPEX uncertainty range of -30% / +50% has been applied. The estimates are intended for high-level screening and comparative analysis, not for final investment decisions. The CAPEX estimates are location-agnostic and are benchmarked against a US Gulf Coast cost basis.

Supply chain integration

In a large and complex system like the LH_2 supply chain, design decisions in one area can significantly affect others and must therefore be considered at a system level. For example, insulation performance in LH_2 loading lines or storage tanks affects BOG compressor sizing and the supply chain capacity. The supply chain model must similarly account for system level interactions to ensure internal consistency and validity of results.

The modelling assumptions used for the LH_2 import/export analysis include:

- **Export Terminal**
  - No pumping is assumed between the liquefier and the storage tanks. LH_2 rundown from the liquefier to storage tanks occurs at 0.5–1.5 barg.
  - The export terminal total BOG flow is steady (4–6% of throughput) and recycled to the liquefier feed. The BOG at the export terminal arises from vapor displacement, LH_2 flashing, pumping and heat ingress.
- **Storage Tank**
  - Spherical storage tanks have a double wall vacuum insulation resulting in a low BOG rate, with insulation performance provided by CB&I.
  - Flat bottom tanks with a non-vacuum insulation have higher natural BOG rates. Typical operating pressure ranges from 50-150 mbar above atmospheric pressure, which results in additional flashing of the liquefier rundown into the tank relative to spherical tanks. However, flat bottom tanks are expected to reduce cost of supply due to CAPEX savings.
- **LH_2 Transfer**
  - LH_2 transfer pumps have been assumed for ship loading operations. Pressure-based transfer is not considered credible due to extended loading times and significant flash vapour generation.
- **Ship Loading**
  - A vapor return line is assumed to balance GH_2 flow between ship and shore tanks (commonly referred to as the piston effect), similar to LNG systems.
  - Intermittent BOG during loading (e.g. from ship tank displacement) is assumed to be managed without requiring significant accommodation over the steady state BOG from storage. This may be achieved by:
    - Applying a 100–250 mbar pressure increase from onshore to ship tanks.
    - Maintaining deep cryogenic temperatures in vapor return lines.
    - Minimising pump induced heat dissipation into the fluid by avoiding excessive pressure.

- **Ship Voyage**
  - The models assume that during the ship voyage the BOG naturally generated in the ship storage tanks (caused by heat ingress and Ortho/Para-H_2 conversion while maintaining constant pressure) will be used as a fuel for ship propulsion, which will be supplemented by conventional low-sulphur fuel. This is considered credible when the BOG rates are less than the total required fuel use. Enabling technologies, such as hydrogen fuelled internal combustion engines and fuel cells, are currently undergoing trials.
  - Alternative strategies (not modelled) for managing BOG on the ship during the voyage include:
    - Suppressing BOG via subcooling at the export terminal or onboard the ship (e.g. using Air Liquide's subcooler [Ref. 7]).
    - Use pressure buildup to (partly) suppress BOG and maximise hydrogen delivery to the import terminal, which is useful when the cost of hydrogen is high. The trade-offs are a higher BOG rate while unloading the ship at the lower pressure import terminal (due to LH_2 flashing), and an increased CI of the LH_2 delivered due to the increased use of conventional low-sulphur fuel.

Economies of Scale and Technology Improvements

Scaling up the LH_2 supply chain is seen as critical for enabling global hydrogen trade at the energy system (GW) scale and decarbonising hard-to-abate sectors. For reference, 500 tpd H_2 is equivalent to approximately 700 MW of lower heating value energy. This section explores our current understanding of economies of scale and outlines potential pathways to cost reduction.

Modelling scenarios

Table 2 shows a series of cases used to illustrate the impact of scale and technology improvements on LH_2 supply chain performance. In all cases, NG derived hydrogen is produced via ATR, incorporating cryogenic carbon capture and domestic CO_2 storage.

Table 2 Case Map of LH_2 Supply Chain Scale-up Scenario

	Today	Short term	Mid term		Base Case	Long term		
		Case 0	**Case 1**	**Case1B**	**Case2**	**Case2B**	**Case3**	**Case3B**
Supply chain, tpd	90(1)	125	250	250	500	500	1000	1000
Liquefaction, tpd	3x30	1x125	2x125	1x250	2x250	1x500	2x500	2x500
LH_2 tank type	Sphere	Sphere	Sphere	Flat bttm	Sphere	Flat bttm	Flat bttm	Flat bttm
LH_2 tank, 1000x m^3	4.7(2)	1x25	2x25	1x45	2x40	1x75	1x110	1x130
Shipping, 1000x m^3	1.25(3)	2x20	2x40	2x40	2x60	2x60	4x80	3x100

(1) SK E&S, South Korea, Air Liquide liquefaction technology
(2) NASA Kennedy Space Center, by CB&I with glass bubble insulation
(3) Suiso Frontier by Kawasaki Heavy Industries

The analysis begins with Case 0 which has 125 tonnes per day (tpd) liquefaction capacity. The technology is commercially available from Air Liquide, although it has yet to be deployed as a capital project. Case 1 scales up to 250 tpd using two 125 tpd liquefaction trains, with increased storage and shipping capacity. Case 1B introduces technological improvements including a larger liquefaction train and a flat-bottom tank. This pattern continues through Cases 2/2B (500 tpd) and 3/3B (1,000 tpd). The “B” cases reflect optimised, cost-effective configurations enabled by technology advancements that are expected to be available in the future, such as further scale-up of the liquefaction train size, ship size, LH2 tank size, and the use of flat-bottom tank. “B” cases advocate and show incentive for technology development.

Case 2, highlighted in red in Table 2, serves as the ''Base Case'' for our further analysis. It is the configuration where scaling the liquefaction train size delivered the most significant benefits, and it is the reference case for all sensitivity analyses presented.

Case 3 shows further train scaling benefits, which are achievable in the longer time horizon once the hydrogen market develops, and sufficient off-take agreements and supply capacities are established.

LCOH and carbon intensity results

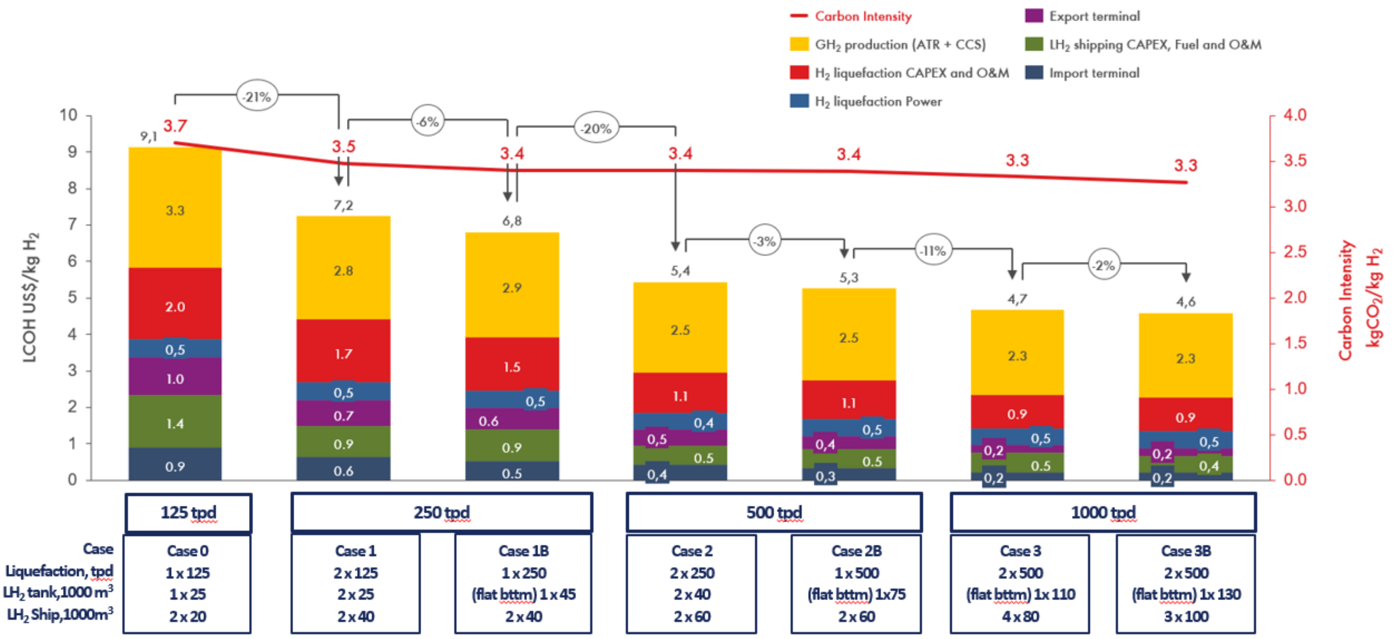

Figure 2 ***LCOH (excluding Tax) & CI Staircase*** *Hydrogen (H_2) Production & LH_2 Supply Chain cases with Carbon intensity (NG derived with CCS) with NG at 8 US$/GJ (8.2 US$/MMbtu), Power at 50 US$/MWh & Carbon transport and sequestration cost at 50 US$/t CO_2 for a domestic Carbon Capture Storage. The NG CI 4.79 kg CO_2/GJ NG, electric power CI 200 tCO_2/MWh, shipping fuel CI (VLSFO) 3.2 kg CO_2/kg fuel and the carbon capture efficiency of 97.4%. Shipping distance of 2000nm.*

Figure 2 shows the LCOH breakdown and the corresponding total CI for all cases. The analysis utilises project-location specific input parameters for hydrogen production modelling, as indicated in the figure caption. The results show a circa 40% reduction in LCOH for a scale-up from 125 tpd (Case 0) to 500 tpd (Case 2) configuration. A 16% reduction is observed when capacity is increased from 500 tpd to 1000 tpd (Case 3B).

Costs in the LH_2 supply chain do not scale linearly with capacity. Higher capacities often require different cost-optimal configurations. For instance:

- **LH_2 tanks** become more economical at larger supply chain capacities due to increased throughput.

- **Large-scale liquefiers** enhance cooling specific energy efficiency, reducing unit and power costs.
- **Replicating technology blocks**, e.g. liquefaction trains or spherical tanks, also yields cost advantages.
- **Civil works** (e.g. jetty, site preparation) and **control systems** scale weakly with capacity, leading to significant reductions in unit costs as production scales.

In contrast, Figure 2 also highlights that improvements in the CI of the imported LH_2 are only weakly linked to supply chain scale. While some minor benefit is observed from reduced specific energy consumption in liquefaction and marginal reduction in shipping emissions through the use of larger carriers, these effects are secondary. A detailed breakdown of CI contributions and sensitivities is provided in the CI sensitivity section.

LCOH sensitivities

While the supply chain scenario mapping in the previous section highlights the impact of scale and selected technology decisions, it is recognised that many input parameters will be project-location specific. To explore regional and project-specific variability, the sensitivity of the LCOH and CI to individual input parameters was evaluated using the "Base Case" (Case 2) as a reference. While this configuration is not necessarily considered "optimal," it provides a credible and representative starting point for the sensitivity analysis.

Two categories of parameters were assessed, and results are summarized in the tornado charts in Figure 3:

- "Project-location" specific parameters: These are directly linked to the project location selection, such as geography, shipping distance, grid power inputs, natural gas supply, carbon transport/sequestration cost, corporate income tax, and renewable energy profiles.
- "Technology" specific parameters: These are largely independent of the site-location and influenced by technology selection and integration decisions. Examples include the hydrogen production method, LH_2 supply chain capacity, storage configuration, BOG management, and ship cargo capacity.

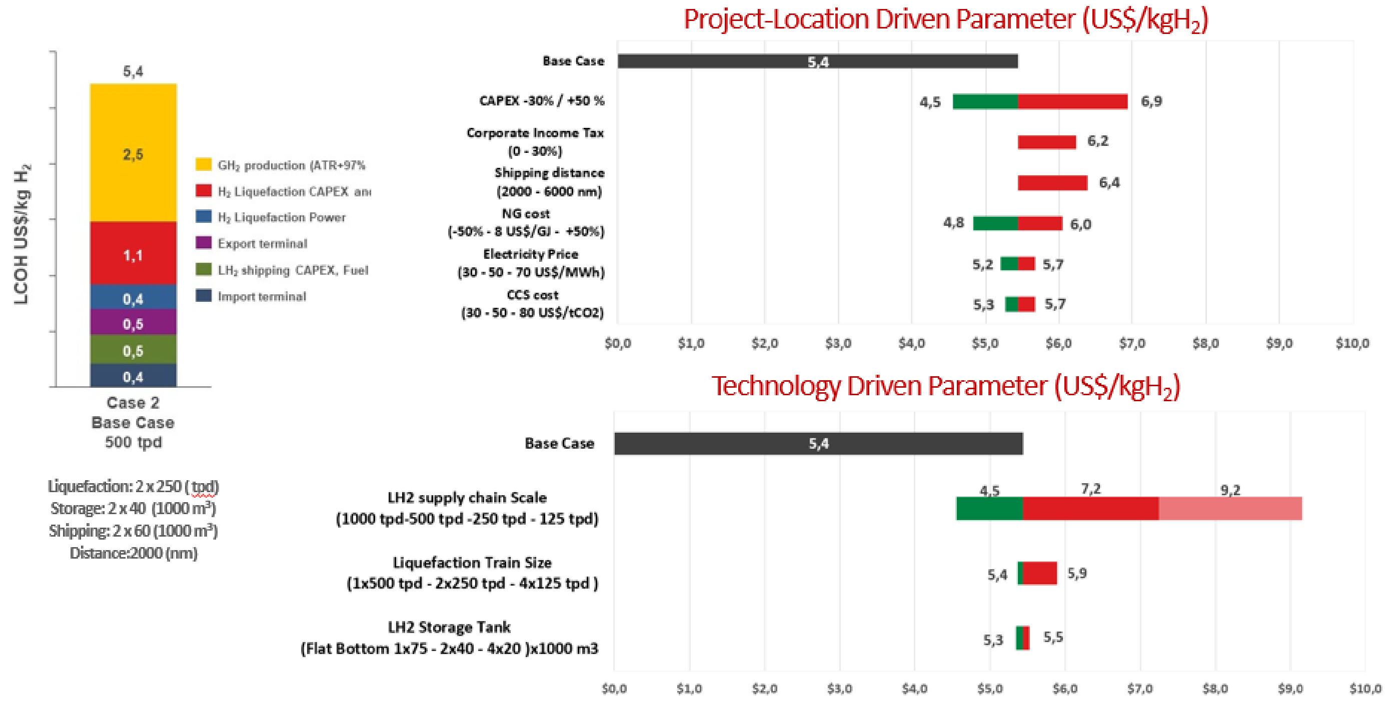

Figure 3 LCOH (Base Case excluding Tax) Impact of Project-Location & Technology Choices (for 500tpd Base Case)

These sensitivities reiterate that supply chain capacity is the most significant lever for achieving lower LH_2 cost.

The shipping distance also has a strong impact on the LH_2 supply chain costs. As part of techno-economic assessment, a long-distance shipping scenario of 6000 nautical miles (nm) was modelled. The configuration required four ships of 80,000 m³ for the same supply chain capacity, compared to two ships of 60,000 m³ each for the Base Case with a shipping distance of 2,000 nm. The increase in both ship size and fleet size substantially raises shipping costs.

Moreover, more BOG is generated on a longer voyage, which in our models is used as shipping fuel, therefore reducing the net quantity of hydrogen delivered to the import terminal. For the long-distance case, BOG consumption reaches 4% of the cargo per round trip, compared to 1.5% in the Base Case. This percentage can vary depending on cargo tank insulation and BOG management strategies. While hydrogen fuel utilisation can help reduce onboard emissions, the proper insulation level will also be assessed to improve the overall system efficiency and ensure compliance with marine regulations.

Other project location parameters have a meaningful influence on the hydrogen cost. The production project location choice may be steered by a compromise between distance to customer and possible agreements securing favourable economic conditions. Achieving low-cost NG, electricity and CCS may offset distance cost penalty, although the CI of the feedstocks must also be considered as we see in the next section.

Apart from the supply chain scale, when considering technology driven parameters the liquefier train size was found to have the greatest potential to reduce costs. The development of a 250 tpd liquefaction train offers substantial benefits in terms of cost reduction and represents a practical compromise between rapid technology scaling risk and cost improvement. In the scenarios presented, further increasing liquefaction train size to 500 tpd appears to bring relatively less cost reduction, however the value of 500 tpd trains is likely to become more visible when facilities larger than 500 tpd capacity are assessed and further performance improvements are achieved at this scale through ongoing technology development.

Given the capital intensity of the LH_2 supply chain, CAPEX variations and uncertainty are expected to play a big role in LCOH. Strong cost discipline should be applied during project development. Improvements in CAPEX may also be achieved through ongoing technology development and through efforts to reduce uncertainty that leads to conservatism in design and higher contingencies in project economics.

Carbon intensity sensitivities

Figure 4 presents the CI breakdown for the Base Case (Case 2). This analysis highlights the relative contributions of key supply chain components—including hydrogen production, liquefaction, shipping, and terminal operations—to the total GHG emissions profile. The breakdown provides a baseline for understanding the dominant emission sources and supports the sensitivity analysis discussed in this section.

Similar to the LCOH sensitivity analysis, the CI sensitivities are assessed by varying both project location specific factors (e.g. grid CI, shipping distance, NG supply CI) and technology driven choices (e.g. liquefaction scale and specific energy efficiency, and carbon capture rate). These analyses help identify the most influential parameters and guide design decisions for reducing the carbon footprint of LH_2 supply chains.

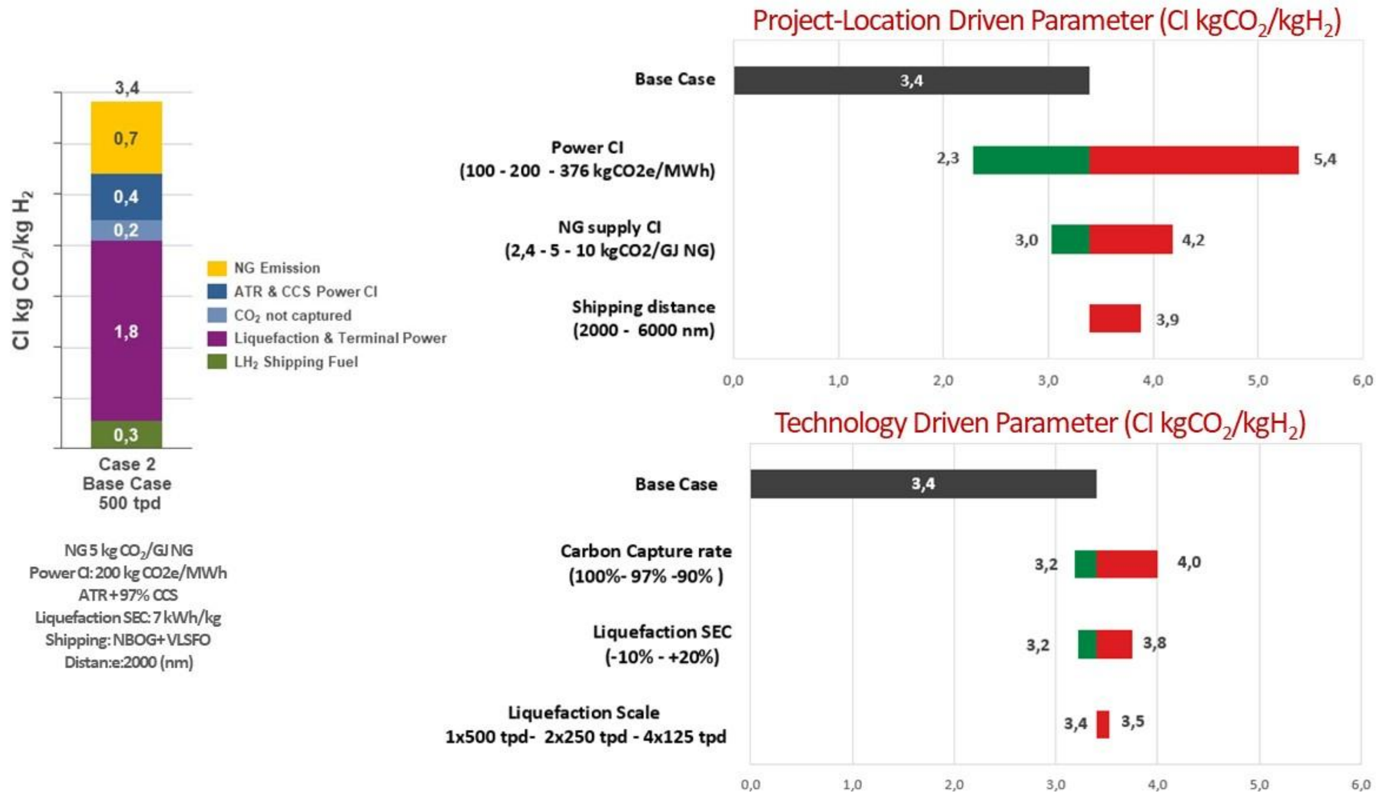

Figure 4 CI Impact of Project location and Technology Drivers

Figure 4 highlights that Power (electricity) is the primary contributor to the carbon intensity of the LH_2 supply chain. This is followed by emissions associated with NG supply, efficiency of CCS, and emissions from shipping fuel. In our modelling, the average grid carbon intensity, supported by a high share of hydropower, was assumed to be 200 tCO_2/MWh, which significantly reduces associated GHG emissions compared to a conventional gas-based power grid with a typical carbon intensity in the range of 400–500 tCO_2/MWh.

To meet emerging CI thresholds for LH_2, depending on the current grid CI in each hydrogen-exporting country, a project may have the option of integrating additional renewable energy into their production systems. Importantly, renewable electricity may not necessarily be more expensive when combined with grid power to mitigate intermittency and ensure a high utilisation. For countries aiming to become major exporters of lower-carbon[1] hydrogen, it is also reasonable to expect a progressive decline in grid CI over time, consistent with historical decarbonisation trends. As a result, grid CIs that support the emerging CI thresholds for LH_2 may be achievable in many regions in the future.

In the analysis the base case for NG supply CI assumes top-quartile performance in upstream methane management [Ref. 23]. The sensitivity range demonstrates the impact of variations and the importance of considering the upstream practices when selecting sites and feedstock supply for large-scale LH_2 production facilities.

While incremental CI reductions can be achieved through improved liquefier efficiency and shipping optimisation (Figure 4), the analysis reinforces that supply chain scale-up alone is not an effective strategy for reducing carbon intensity. Furthermore, most technology choices have limited impact on CI, with the exception of higher carbon capture efficiency, which can play a meaningful, but ultimately limited, role.

Ultimately, the most effective way to manage CI is through the strategic selection of lower-carbon[1] power and natural gas sources, as these inputs have the greatest influence on the overall emissions profile of the LH_2 supply chain.

Comparative assessment of hydrogen production methods

While the above sensitivities focussed on the NG derived hydrogen Base Case, PROPELH2 also evaluated the renewable electrolytic hydrogen production pathway to assess its potential impacts on both LCOH and CI. A representative scenario was developed using a 500 tpd supply chain capacity, for a shipping distance at 2000 nm, consistent with the Base Case to ensure comparability across production methods.

Figure 5 presents the results of this comparative assessment, focusing on two distinct renewable hydrogen production cases: one utilising a moderate renewable power profile, and the other based on an optimal renewable profile with highly complementary wind and solar. Both cases were benchmarked against the Base Case to highlight the trade-offs between cost and GHG emissions performance.

In the NG derived hydrogen scenarios, reductions in cost of GH_2 production are largely driven by lower natural gas prices and by favourable CCS economics. However, the associated CI remains larger than the renewable hydrogen scenarios, primarily due to the grid carbon intensity, upstream methane emissions and the limitations of carbon capture efficiency.

The renewable hydrogen scenarios demonstrate a substantial reduction in CI, noting that both the hydrogen production and the liquefaction are powered by renewable electricity in these cases. However, even for optimal renewable profiles, the LCOH is more than 2.5-3 US$/kg H_2 higher compared to the equivalent NG derived hydrogen case. This cost premium is largely attributable to the intermittency of renewable energy, which necessitates overbuild of renewables and the integration of battery energy storage systems (BESS) to ensure stable electrolyser operation.

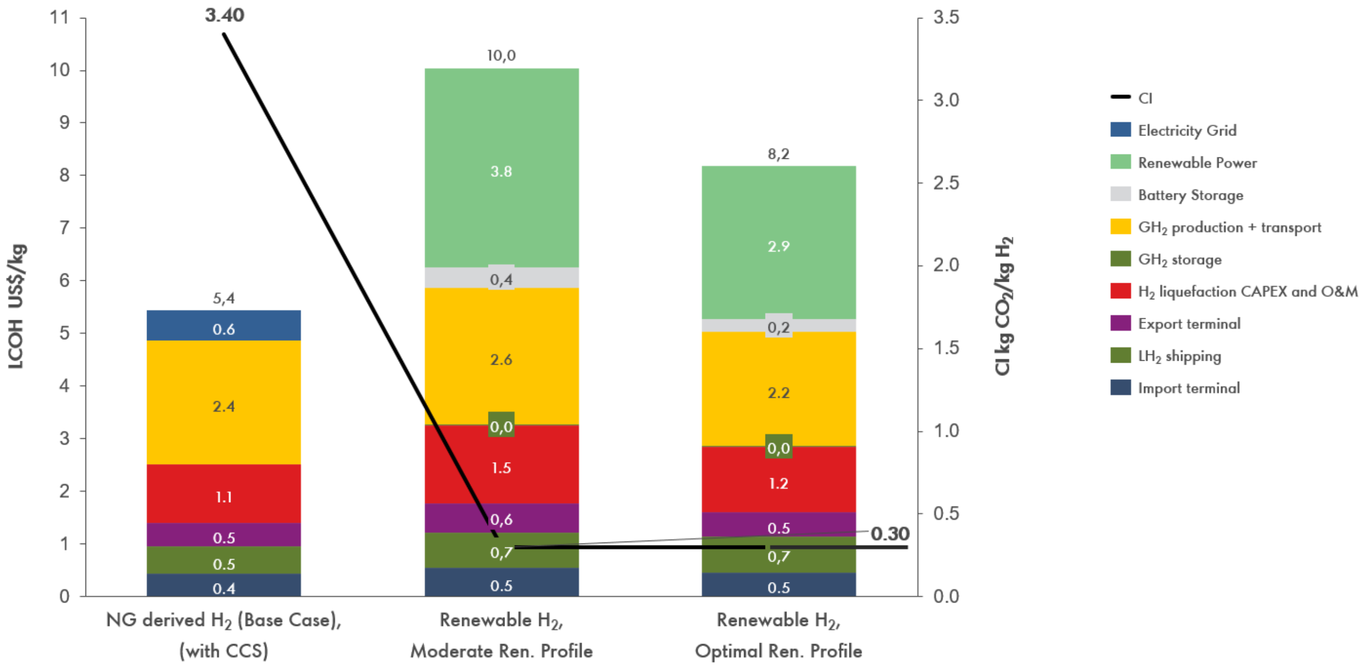

Figure 5 Comparative assessment of hydrogen production scenarios. Renewable GH_2 low case is based on strong renewable profiles with complementary wind and solar resources. Renewable GH2 high case is based on moderate renewable profiles; Electrolyser cost at 2000 US$/kW, Solar PV at 780 US$/KW, Wind at 1200 US$/kW, BESS at 320 US$/kW. All LCOH values exclude Tax.

Key insights

The PROPELH2 study's comprehensive techno-economic modelling has yielded the following key insights:

- Scale of the facility and LH_2 supply chain is the primary lever to reduce the cost of hydrogen supply. It is anticipated that hydrogen may become commercially viable without subsidies for certain end-users if facilities of 500 tpd can be developed, noting that there are diminishing returns for scale beyond this size, as highlighted in Figure 2.
- The CI of the NG derived (with CCS) LH_2 supply chain is primarily influenced by the grid CI and the CI associated with the upstream natural gas production. A long shipping distance can also have a significant impact on the CI.
- Production site selection should therefore consider both the cost and CI of key feedstocks and utilities, with the CI being especially important for cases with a longer shipping route.
- A fully integrated supply chain view for both LCOH and CI criteria is necessary for each opportunity.
- For a given site and facility scale, a focus on optimising the liquefaction train and shipping configuration, including integration between the export facility design and shipping operations, is recommended and could reduce cost of supply by 10-15%.

- A push for novel and large-scale technology development is essential to unlock the economy of scale. Even for a fixed supply chain capacity, technology improvements have the potential to reduce the LCOH in the order of 10%.
- Further cost reductions may be achieved by leveraging the build-out of LH_2 infrastructure, utilising tolling arrangements for import-terminals, and time-chartering of LH_2 carriers.

Technology Readiness

Significant technology development is required to enable LH_2 supply chain capacities of 250 to 500 tpd. Collaboration with technology providers for key components – hydrogen liquefaction, LH_2 storage, LH_2 shipping – has established a clear path towards the required technology development programs. Other technologies, such as high volume LH_2 pumps and marine loading arms, are already progressing. In contrast, components like larger valves and cryogenic hydrogen flares, will require further industry engagement to confirm technology scale-up pathways.

H_2 liquefaction

Hydrogen Liquefaction is a well-established technology up to 30 tpd train size with many units built and operated over several decades by multiple suppliers. There are multiple 30 tpd references in operation. Air Liquide's 30 tpd references have a specific energy consumption (SEC) of about 10 kWh/kg.

Air Liquide has developed efficient and leading technologies for large-scale hydrogen liquefaction and BOG management to enable a scale-up to larger train sizes. Strong collaboration with Air Liquide experts has been key in optimizing performance, identifying advanced technology solutions and sharpening techno-economic modelling for large scales.

Through collaboration with Air Liquide in the PROPELH2 study key learnings included:

- Scaling up the train size is crucial for reducing the specific cost and LCOH of hydrogen liquefaction and is a key enabler to achieve liquefaction SEC of less than 7 kWh/kg. Air Liquide's commercial 125 tpd concept (referenced in "Case 0") significantly improves LCOH and SEC compared to state-of-the-art 30 tpd units, with further cost reductions achievable through additional scale-ups:
  - Scale-up from 125 tpd to 250 tpd is expected to result in a specific CAPEX cost reduction in the order of 30%.
  - Subsequent scale-up from 250 tpd to 500 tpd is expected to result in another specific CAPEX cost reduction in the order of 15%.
- Key challenges for 250 tpd and 500 tpd trains lie in the scale-up of the hydrogen expanders, compact heat exchangers and cold boxes design.
- Remaining technologies are relatively mature, but their scale-up and integration in a large-scale liquefaction design will still require further development: hydrogen compression, nitrogen compression, catalyst and cryogenic hydrogen purification.

- Hydrogen compression becomes a particular focus area when scaling to 500 tpd as the number of reciprocating compressors required would be excessive. Therefore, it relies on development and qualification of centrifugal compression for hydrogen.
- Liquefier can have 50% turndown capacity, or better, which is beneficial when integrating with intermittent renewable GH_2 and/or power.
- Technology roadmaps are being developed to address the technology challenges mentioned above for the design and testing of large-scale H_2 liquefiers on the 250 tpd to 500 tpd scale.

LH_2 storage

Vacuum-insulated LH_2 tanks are established technology, with existing bullet (cylindrical) tanks in sizes up to approximately 1000 m^3 and existing spherical tanks in sizes up to approximately 5000 m^3. CB&I offers a design concept for vacuum-insulated spherical LH_2 tanks up to 40,000 m^3 at significantly reduced specific cost of storage compared to small tanks and with boil-off rates less than 0.05%/day. Such large tanks have not been built yet, and qualification efforts are still required. Construction of spherical tanks is time consuming and likely to enter the project critical path.

Further improvements in the specific cost of storage are expected to require a change in storage tank technology. As tank capacity increases, the cost to design the vacuum jacket to resist buckling becomes prohibitive. Therefore, a consortium including Shell, CB&I, NASA, GenH2, University of Houston, with support from the US Department of Energy, has developed a non-vacuum insulation concept for LH_2 storage (Project ID: ST241). The key challenge to commercializing the technology is the demonstration of the insulation's long-term (30 year) mechanical integrity at LH_2 temperatures. This insulation is in the development phase and has been applied and will be tested in a 20 m^3 LH_2 tank at the NASA Marshall Space Flight Center's Hydrogen Test Facility.

Utilising this insulation technology, CB&I have developed a non-vacuum flat bottom tank design with the potential to scale to 100,000 m^3 and larger capacities. The use of a flat bottom tank configuration is similar to conventional LNG storage tanks and allows for efficient construction with the potential to halve the capital cost and significantly reduce the delivery time of large-scale storage. It is anticipated that a scaled-down flat bottom tank demonstration project will be required before it can be applied in large scale LH_2 export/import projects.

LH_2 shipping

The first successful non-commercial demonstration of LH_2 shipping, carried out between Australia and Japan, was completed by the 1250 m^3 capacity MV Suiso Frontier, built by Kawasaki Heavy Industries and operated by Shell [Ref. 8]. A second LH_2 demonstration vessel, supported by the South Korean government, with a total cargo capacity of 2000 m^3, is currently under development and is expected to be built by 2027 [Ref. 9].

Approval in Principle (AiP) has been awarded to shipyards Kawasaki Heavy Industry [Ref. 10], HD KSOE [Ref. 11], Samsung Heavy Industries [Ref. 12] and Hanwha Ocean (together with CB&I) [Ref. 13], by various classification societies (hereinafter referred to as "class"), for concepts in LH_2 carrier and/or proprietary cargo containment system designs.

Most current designs incorporate cargo capacities in the 20,000 to 80,000 m^3 range. While none of the shipyards have yet announced progression to Front End Engineering and Design (FEED), some are expected to reach that stage within the next 12 months.

In parallel to the development work by the shipyards, multiple independent technology providers (e.g. Moss Maritime, GTT, CB&I) are advancing cargo containment system technologies, with AIPs awarded by class [Ref. 14, 15, 16].

Due to the low density of LH_2, hull design requirements differ from conventional LNG carriers. Optimising the hull and propulsion systems is therefore critical to improving energy efficiency and reducing both fuel costs and emissions. Hydrogen internal combustion engines are being developed by a number of companies including Wartsila, Everllence, HD Hyundai Heavy Industries & Machinery [Ref. 17, 18, 19], and PEMFC have already been demonstrated in pilot projects [Ref. 20, 21].

Key cost drivers to improve the LH_2 shipping freight (US$/kg/mile) are primarily driven by the cost and complexity of the cargo containment system, the fuel selection and efficiency of the propulsion system. In general, larger vessels offer lower freight costs, but maximum ship size is constrained by supply chain capacity, shipping distance, and the preferred fleet size.

Insights from the collaboration with HD-KSOE include:

- HD KSOE has designed a large-scale vacuum-insulated LH_2 storage tank for use on LH_2 carriers (LH_2C). Testing of the vacuum insulation solution has been completed, which verified tank scale-up feasibility, prior to AiP announcement January 2025 [Ref. 22]. There are plans for further testing in the later part of 2025.
- Planned completion of pre-FEED design for the 60,000-80,000 m^3 LH_2C by the end of 2025.
- Readiness for marine hydrogen engine progressed, including H_2-LNG engine test (2022), H_2-Diesel engine test (2024), and hydrogen only engine test (2025).
- LH_2 carrier shipbuilding readiness to be aligned with hydrogen shipping project progress.

Other technologies

Figure 6 visualises the technology maturation for key technologies, including the dimensions and capacities that are required for 500–1000 tpd LH_2 supply chain. So far, the PROPELH2 study has focussed on the big building blocks. However, a supply chain is as strong as its weakest link. Therefore, further industry engagement is needed to confirm technology scale-up pathways for the remaining LH_2 service technologies: Vacuum Insulated Piping (VIP), valves, fittings, LH_2 transfer pumps, marine loading arms and cryogenic H_2 flare. The supply chain can also be improved by development of other equipment such as: LH_2 instrumentation (e.g. ortho/para H_2 fraction measurement), LH_2 pump for regasification (high flow + high DP), regasification vaporisers, cryogenic (20K) hydrogen blower.

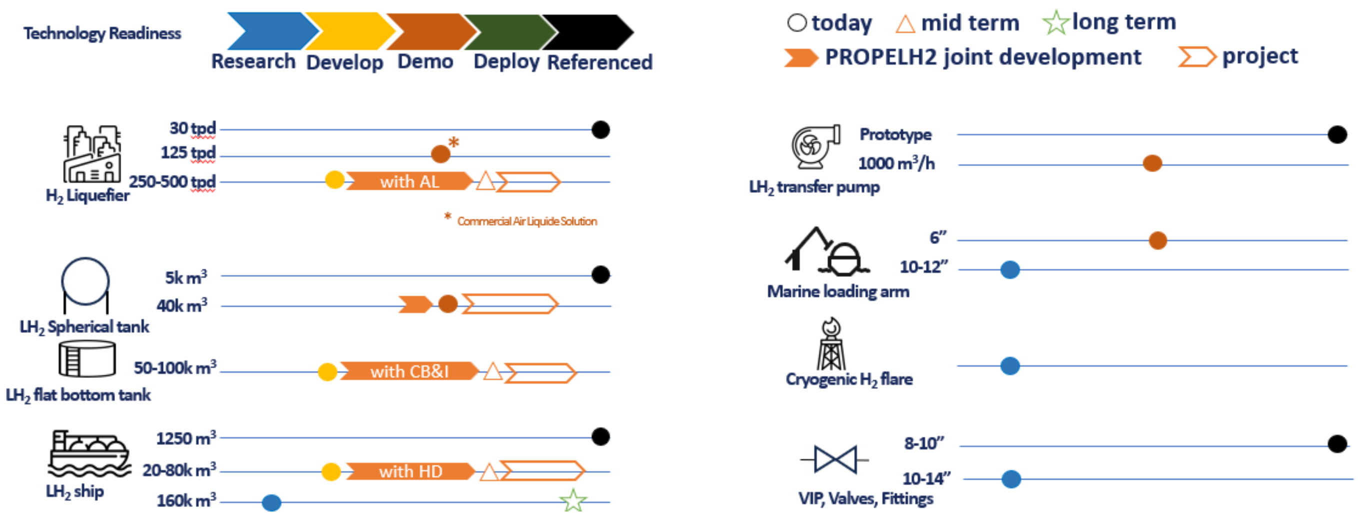

Figure 6 Technology Maturation Overview - LH_2 Supply Chain. "Project" identifies where further technology development requires deployment in a project.

Safety Risk Management

Whilst LH_2 facilities have been operating safely around the globe for many decades, scaling of the LH_2 supply chain up to 500-1000 tpd introduces new safety challenges. Woodside and Shell have conducted safety reviews across the liquid hydrogen supply chain to identify changes in the risk profile, uncertainties and data gaps associated with the supply chain scale-up. These are due to, amongst other things, the significant larger volumes of flammable inventories being stored and transported, as well as the limited experience of technology vendors and operators with construction, commissioning and operation at this scale. Additionally, novelty associated with marine loading/unloading and shipping of LH_2 must be well understood and managed. Current safety codes and standards are not fully applicable to large-scale liquid hydrogen production, storage and transport. This highlights the importance of cross industry collaboration to effectively manage process safety risks in first-of-a-kind projects.

The fragmented nature of applicable codes and standards, combined with limited historical data, and a lack of experimental evidence, contribute to conservative design assumptions that may impact project feasibility. These uncertainties can be effectively addressed through collaboration with LH_2 operators, original (cryogenic) equipment manufacturers, the LNG industry, and qualified third-party verifiers. By combining this expertise and investing in targeted research and design validations programs, the LH_2 supply chain could be scaled and operated safely, potentially creating an essential foundation for the success of the hydrogen economy.

Unlocking the potential of GW scale LH_2 import

Development pathway

There are many technical and non-technical business drivers that must be balanced on the development pathway to large scale LH_2 export/import projects, with key aspects visualised in Figure 7.

In this paper, we primarily focused on one key lever, the LCOH of decarbonised hydrogen supply. LCOH is one of the most important parameters to understand when comparing the competitive position of LH_2 export/import relative to alternative options for hydrogen transport, or alternative decarbonisation pathways. However, safety risks and performance should not be overlooked. For the development pathway discussion below, we assume that in the long term LH_2 will be competitive in several markets at energy-system (GW) scale.

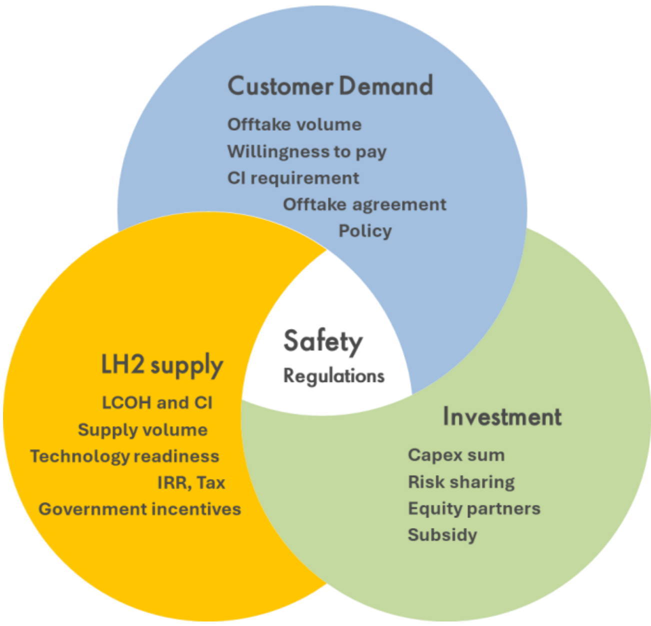

Figure 7 Key Business Drivers on Development Pathways for Large Scale LH_2 Export/Import projects

Due to the requirement for further technology development, and the significant investment required for large-scale supply chains, it is expected that the LH_2 industry will develop through scaled steps over time, as outlined in Table 3.

Table 3 Phased Development Pathways for Large-Scale LH2 Supply Chain

	Short term	Mid term	Long term
Supply	30-125 tpd LH_2 domestic supply Tech scale-up and demos Contract for Difference	LCOH 7-10 US$/kg LH_2 (excluding tax) 250 tpd LH_2 import Deploy large scale tech Contract for Difference	LCOH <5 US$/kg LH_2 (excluding tax) 500-1000tpd LH_2 import Replicate technology
Demand	Current market + First movers Tech demos	Policy <Giga Watt scale Demand aggregation Deploy tech	Policy > Giga Watt scale Large offtakes Replicate tech
Investment	Lower CAPEX Subsidy	Share risk Subsidy	Reduced risk
Business Environment	Uncertain/volatile Domestic projects Create line of sight	Emerging markets Strong partnerships Line of sight	Developing markets Clear business case

In the short term, the cost of LH_2 is expected to be relatively high, and the demand from existing niche markets that can afford this high price is relatively small. The scale-up and development of novel LH_2 technologies can proceed with the support of policy incentives and innovative first mover customers. A key challenge is anticipated to be creating opportunities for early technology demonstrations, especially in new markets. The business environment for LH_2 is likely to be uncertain, and subsidies may be essential to achieve the required technology demonstrations. To keep pace and momentum, it will be important to keep a clear line-of sight to the first deployment opportunities in the mid-term.

In the mid-term, it is most important that the demand for lower-carbon hydrogen grows, and future markets start to emerge. For this to happen, a supportive policy framework is essential. Immediate development of 500-1000 tpd LH_2 import projects is expected to be too large an investment in view of the technology and business risk at this point. A project in the order of 250 tpd may be the right size to balance all the business drivers. By this time, scaled-up technologies should have the potential to be demonstrated and ready for deployment, which is expected to start reducing the LCOH. Additionally, such a mid-term development could be designed to be the first development phase of a planned larger facility, potentially allowing for quick succession to further lower LCOH with subsequent phases.

The investment for a ~250 tpd supply chain is still substantial and the risk is significant. Collaborative investment, such as joint ventures, and government support in the form of price compensation (CfD) and/or investment subsidies would most likely be required. It should be a near term priority to develop strong private-public partnerships to facilitate the potential development of the mid-term LH_2 supply chain opportunity.

In the long term, the LCOH could be further reduced by increasing the supply chain capacity. Technology replication and increased utilisation of export and import terminals are clear cost levers, but so is further scale-up of the technology. In this scenario the LH_2 supply chain would be proven technology, enabling the required investment. Due to the scale-up, and clear policy framework in place, reduced LCOH would have the potential to meet the customer 'willingness to pay'.

Key takeaways

The key findings of the PROPELH2 study are as follows:

- To become relevant at energy-system (GW) scale, the LH_2 supply chain should reach capacities in the order of 500-1000 tpd. The PROPELH2 study demonstrates that large-scale LH_2 supply chains are technically feasible and have the potential to become a competitive solution for global hydrogen trade.
- The prime lever to reduce the LCOH of delivered LH_2 is scaling up of the LH_2 supply chain.
- Once 500-1000 tpd capacities are reached, the cost of "transporting" hydrogen via the LH_2 export/import supply chain is estimated at 2-4 US$/kg$H_2$ (excluding tax). Considering the large window of uncertainty to predict the cost of LH_2 and alternative hydrogen vectors in the long run, it is anticipated that LH_2 has the potential to offer a competitive solution.
- There are many technical and non-technical business drivers that must be balanced on the development pathway to large-scale LH_2 export/import projects. This cannot be resolved by a single company but will require further industry collaboration in addition to existing efforts.
- It is expected that policy development will set the pace. While supply-side progress is critical, without demand certainty, the hydrogen market is not expected to scale.
- Shell, Woodside and technology collaborators aim to continue the technology development roadmap. To build the momentum, we will be looking for opportunities to grow our partnership (PROPELH2) with committed parties both from a technology evaluation and deployment perspective.

Nomenclature

AIP	Approval in Principle
ATR	Auto-Thermal Reformer
BOG	Boil-Off Gas
BOP	Balance of Plant
BOR	Boil-Off Rate
CAPEX	Capital Expenditure
CBAM	Carbon Border Adjustment Mechanism
CCS	Carbon Capture and Storage
CfD	Contracts for Difference
CI	Carbon Intensity
CRF	Capital Recovery Factor
DOE	Department of Energy (USA)
ERV	Emergency Relief Valve
FEED	Front End Engineering and Design
GHG	Greenhouse Gas
GH_2	Gaseous Hydrogen
GW	Giga Watts
H_2	Hydrogen
IRR	Internal Rate of Return
JIP	Joint Industry Project
LCOH	Levelised Cost Of Hydrogen
LH_2	Liquid Hydrogen
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
MLA	Marine Loading Arm
NG	Natural Gas
OEM	Original Equipment Manufacturer
OPEX	Operational Expenditure
POX	Partial Oxidation
QRA	Quantitative Risk Assessment
RAU	Reliability, Availability and Utilisation
RED	Renewable Energy Directive
SEC	Specific Energy Consumption
SMR	Steam Methane Reforming
VIP	Vacuum Insulated Piping
VLSFO	Very Low Sulphur Fuel Oil

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Notes

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The footnotes to this document may provide clarification regarding the use of terms such as "lower-carbon". A full glossary of terms used in connection with Woodside's climate strategy is contained in the CTAP.

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