

Study of Hydrogen Imports and Downstream Applications for Singapore



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- Singapore Civil Defence Force (SCDF)
- Singapore Economic Development Board
- Singapore LNG Corporation Pte Ltd
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- Singapore Refining Company Pte Ltd
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More details of the public consultation process can be found on
<http://www.kbr.com>

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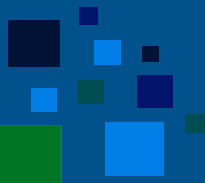
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01

Foreword

"As the world transitions to a carbon-constrained energy future, Singapore must meet the challenges of decarbonizing all sectors while ensuring a clean, reliable and affordable energy supply."



Climate change is a global crisis and also represents an existential challenge for Singapore. As the world transitions to a carbon energy future, Singapore must meet the challenges of decarbonising all sectors while ensuring a clean, reliable and affordable energy supply. Given its limited alternative energy options, Singapore is looking towards emerging low-carbon technologies, including hydrogen, as a potential solution to improve the long-term security and sustainability of its energy supply.

Hydrogen has been studied as an energy solution for 145 years. The International Energy Agency (IEA) expects that by 2050, green hydrogen, which is hydrogen produced from renewable sources, could potentially achieve 25% of required carbon abatement to limit global warming to 2°C¹. When hydrogen is used to produce energy, water is the only by-product. Commercial production of green hydrogen harnesses energy from renewable resources and water, making it a pollution-free fuel.

However, low carbon hydrogen technologies are currently nascent, and a global hydrogen supply chain has yet to be developed. This study explores the feasibility of hydrogen imports and downstream applications to better understand the potential role of hydrogen usage in Singapore to 2050.

Possible benefits of hydrogen deployment in Singapore include enhanced air quality, lower carbon emissions, development of new industries and creation of new employment opportunities, thus helping to ensure a sustainable future for Singapore.

Singapore has long been considered a technologically advanced country with a strong research, development and demonstration (RD&D) community. Advancement of hydrogen technologies and integration into the economy would create an opportunity to further strengthen RD&D capabilities and allow Singapore to showcase and share its hydrogen competencies, whilst also continuing to draw on the experience of international partners.

Given current constraints as an alternative energy-disadvantaged country, Singapore could take advantage of its existing brown hydrogen, hydrogen produced using fossil fuels, and natural gas infrastructure to pilot the use of hydrogen in suitable downstream applications, with a clear pathway towards the eventual use of low-carbon hydrogen. As such, larger volumes could be progressively imported from international projects. This provides Singapore with an opportunity to develop new international relationships with emerging renewable energy-rich nations and strengthen existing strategic partnerships.

The technological aspects of a hydrogen economy are being developed at a rapid pace by many private and government stakeholders. Nonetheless, as several key hydrogen technologies are still nascent in comparison with fossil fuels, policy levers and funding may need to be put in place to support the competitiveness of hydrogen across suitable downstream applications and accelerate the adoption of hydrogen as a fuel in Singapore. The green hydrogen market is a disruptive one, making future energy markets difficult to predict. Moreover, the mass adoption of hydrogen technologies could contribute to steeper reductions in green hydrogen production prices than current projections.

As one of the first countries in the Asia-Pacific (APAC) region to study the potential of hydrogen deployment, Singapore can partner with regional importing nations, such as Japan and South Korea, and exporting nations such as Australia, New Zealand and Malaysia to accelerate the adoption of a regional hydrogen economy. Through the development of a domestic hydrogen economy, Singapore could play an important role as a hydrogen hub within the APAC region and export knowledge and technologies developed to neighbouring countries.



¹ Hydrogen scaling up – A sustainable pathway for the global energy transition, [<https://hydrogencouncil.com/wp-content/uploads/2017/11/Hydrogen-scaling-up-Hydrogen-Council.pdf>].

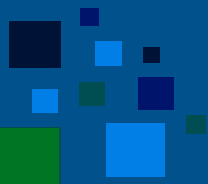
Nomenclature

Category	Icon	Description	Category	Icon	Description
Hydrogen Carriers		» Hydrogen	Downstream Sectors		» Mobility
		» Liquefied Hydrogen			» Private Car
		» Ammonia			» Taxi
		» MCH			» Bus
		» LOHC			» Light Goods Vehicles (LGVs)
		» Methanol			» Heavy Goods Vehicles (HGVs)
Sources of Energy		» Wind			» Industrial and Manufacturing / Merchants
		» Solar			» Fuel Users and Auto Producers
		» Renewable Electricity			» Maritime and Ports
		» Natural Gas (NG)			» Bunker Tankers
		» Fossil Fuel			» Passenger Boats
		» Bioenergy			» Tugboats
Production Technologies		» Electrolyser			» Cranes
		» Steam Methane Reformer (SMR)			» Yard Trucks
		» Gasification		» Power Generation Sector / Gencos	
Storage and Distribution		» Storage		» Non-Industrial Gas	
		» Trucking			
		» Piping			
Other		» CO ₂			
		» Carbon Capture			

02

Introduction

"The use of emerging technology sources to diversify Singapore's fuel mix is being examined as one the possible pathways to meet Singapore's Long-Term Low Emissions Development Strategy."



Singapore aims to peak its absolute emissions at 65 MtCO₂e around 2030, which represents a reduction of greenhouse gas emissions intensity by 36% below 2005 levels. In February 2020, Singapore announced its Long-Term Low Emissions Development Strategy (LEDS) to halve its peak emissions from 65 MtCO₂e to 33 MtCO₂e by 2050, with the view of working towards net zero emissions as soon as viable in the second half of the century. To meet its LEDS targets, emerging low-carbon alternatives to diversify Singapore's fuel mix and decarbonise various sectors of the economy include some of the pathways being examined. As a clean fuel, a low-carbon energy carrier and a means of storing energy, hydrogen could play a key complementary role to fossil fuels in Singapore. Additionally, it provides an opportunity for Singapore to develop new export technologies to promote a clean energy market regionally and globally.

For hydrogen to become part of Singapore's energy mix in a secure, affordable and sustainable way, a series of challenges and practical issues needs to be addressed along all aspects of the hydrogen supply chain. This includes:

- Identifying cost-competitive international or indigenous low-carbon hydrogen production opportunities.
- Overcoming the technical and economic challenges associated with transporting and storing hydrogen internationally.
- Addressing the practical and regulatory issues in hydrogen deployment into various locations and sectors of the economy, including power generation, industrial, domestic heating and gas, and mobility (including public and private mobility).
- Identifying other developments and 'tipping points' which could enhance hydrogen's role as a fuel, energy carrier and feedstock to decarbonise the chemical industry.

In September 2019, the National Climate Change Secretariat (NCCS), Economic Development Board (EDB) and Energy Market Authority (EMA) commissioned a study of the technical and economic feasibility of importing and using hydrogen in Singapore up to 2050. The study assessed potential sources of hydrogen imports to Singapore, suitable downstream applications, identifying RD&D opportunities to advance hydrogen technologies in Singapore, and recommending solutions to address hydrogen-related policy and regulatory challenges.

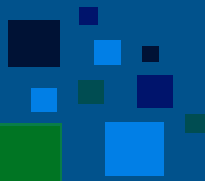
The main study objectives are:

1. Assess potential sources of hydrogen imports to Singapore based on availability, cost, technical feasibility and supply security.
2. Evaluate feasibility and gaps of utilising Singapore's existing infrastructure (e.g., Liquefied Natural Gas (LNG), natural gas, town gas) to receive/unload, store, transmit and transport hydrogen domestically for downstream applications.
3. Assess and recommend solutions to address the technological, policy and regulatory challenges to the import and use of hydrogen in Singapore.
4. Provide a high-level estimate for hydrogen demand across the Southeast Asian region and regulatory challenges for hydrogen import and usage.
5. Provide a high-level estimate for hydrogen demand across Southeast Asia and synergies that could be derived from increased regional hydrogen demand.

03

Approach and Methodology

"The results of stakeholder engagement and extensive review of sources, coupled with market analysis and forecast, enabled a robust and Singapore-specific analysis of how hydrogen could be deployed in the future."



The study was conducted in two parallel and complementary phases. The first phase was a literature review and the second phase involved engagement with over 100 Singaporean and international stakeholders from all aspects of the hydrogen supply chain. Stakeholder engagement took the form of one-on-one interviews and two full-day workshops. Consultant's internal expertise and analysis was utilised throughout the study.

The primary goal of workshop one was to explore, validate and identify the challenges and opportunities around the adoption and facilitation of a hydrogen-based economy across the entire supply chain. To facilitate this, the following objectives were established:

- Identify and explore existing and additional challenges for each sector in hydrogen adoption.
- Identify where hydrogen provides opportunities in each sector.
- Develop high-level strategies to mitigate challenges and capitalise on opportunities.
- Identify where hydrogen provides unique economic advantages for Singapore.

From the analysis of various sources and initial workshops and interviews, deployment pathways for Singapore's downstream sector were developed. These were presented for feedback from the stakeholders during workshop two. To facilitate this, the following objectives were established:

- Provide participants background information on the scenarios to be analysed.
- Scan potential deployment pathways with respect to the defined pillars.
- Identify potential challenges for each scenario.
- Identify potential approaches to transition for each of the scenarios, in addition to the journey toward 2050 goal: Halve the emissions it produces from its 2030 peak.

Workshop output helped to define deployment pathways and also provided an appreciation of the Singaporean context.

One-on-one stakeholder interviews were centred around gathering more detailed technical information, including CAPEX, efficiency improvements, experience, and deployment timelines for the analysis to complement the literature review. Furthermore, the interviews also explored stakeholders' decarbonisation plans in Singapore as well as internationally, including introduction of hydrogen into their operations.

Insights obtained from stakeholder interviews and workshop outputs, as well as technical information gathered from the market participants, were used to supplement the review of sources. These helped derive landed costs and breakeven models. These two models were used to conduct the market analysis. The first model, the Singapore hydrogen landed cost model, calculates the landed cost of hydrogen in Singapore from a range of locations on an annualized basis. Cost is characterised as the function of hydrogen production, the choice of hydrogen carrier, the relative rate of technological progress of the different technologies along the value chain, and distance to Singapore. At each stage of the supply chain, a bottom-up cost analysis was conducted wherein capital and operating costs were modelled. The cost/price determined at each stage is then used as input into the next stage of the hydrogen cost build-up along the supply chain.

To complement the cost of landing hydrogen in Singapore, the breakeven model was developed to assess the competitiveness of hydrogen in downstream sectors. The breakeven model estimates the price at which hydrogen would be considered a viable substitute to the alternative being considered. The costs of transporting hydrogen from import terminals to end sectors are explicitly characterised in the model.

The results of stakeholder engagement and extensive review of sources, coupled with the market analysis and forecast, enabled a robust and Singapore-specific analysis of potential hydrogen development pathways.

04

Hydrogen Production

"Given growing international desire to reduce carbon emissions and dependence on fossil fuels, several less carbon-intensive technologies are being developed and deployed to produce hydrogen using renewable energy sources."



Hydrogen can be produced using a number of different routes as shown below:

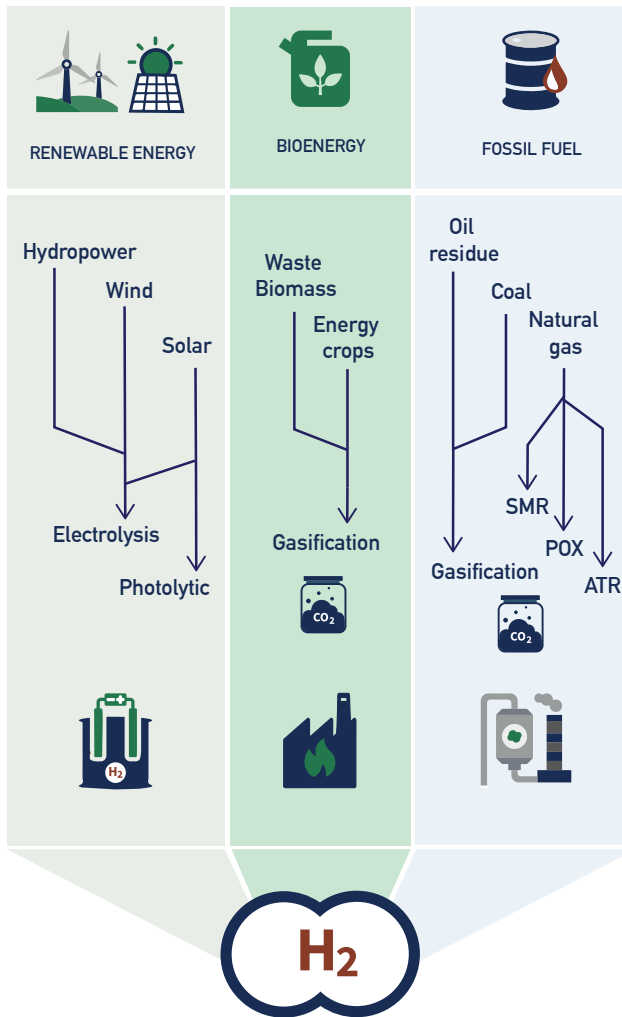


Figure 4.1 - Common Hydrogen Production Pathways

Currently, around 70 Mt of hydrogen is produced worldwide annually, with the most common production methods being steam methane reforming (SMR) of natural gas and coal gasification. The remainder of hydrogen production is derived from partial oxidation of oil and electrolysis from renewable sources. Due to the reliance on hydrogen produced from fossil fuels, total carbon emissions from hydrogen production amounts to 830 Mt of CO₂ annually¹.

For the purpose of this study, hydrogen generated from fossil fuels is referred to as 'brown hydrogen'. If CO₂ emissions from brown hydrogen production are avoided or significantly abated, for example, using CCUS technologies with steam methane reforming of natural gas, then it is referred to as 'blue hydrogen'. Hydrogen generated from renewable energy or renewable sources is called 'green hydrogen'. Hydrogen produced from natural gas using methane pyrolysis technology is called 'turquoise hydrogen'.

Currently, there is no international entity dedicated to the certification of hydrogen and issuance of Guarantee of Origin (GO) and therefore, the hydrogen nomenclature. The CertifHy project in Europe is designing the first EU-wide Green and Low-Carbon Hydrogen Certification System and has developed a Green and Low-Carbon Certification pilot that has led to the issuance of over 76,000 GO, of which more than 3,600 have already been used². Initiatives such as CertifHy may extend to other regions to promote low-carbon adoption, support the efforts to transition to a low-carbon economy, and establish a common language for the hydrogen industry to enable transparency across different markets.

Given the growing international need to reduce carbon emissions and dependence on fossil fuels, several less carbon-intensive technologies are being developed and deployed to produce hydrogen using renewable energy sources.

The hydrogen nomenclature used for this report and production pathways are given below.

Table 4.0 - Hydrogen Nomenclature and Pathways

	COMMON PRODUCTION TECHNOLOGY	PRODUCTION PATHWAY
BROWN HYDROGEN	<ul style="list-style-type: none"> Steam methane reforming Coal gasification Methane pyrolysis (depending on feedstock and heating source) 	<ul style="list-style-type: none"> Produced using fossil fuel sources, such as coal, oil and natural gas, and accounts for 96% of current global hydrogen production³.
BLUE HYDROGEN	<ul style="list-style-type: none"> Steam methane reforming with CCUS Coal gasification with CCUS 	<ul style="list-style-type: none"> Blue hydrogen is produced either from brown production methods as described above coupled with CCUS
GREEN HYDROGEN	<ul style="list-style-type: none"> Water electrolysis with renewable electricity Solar thermochemical Biomass gasification Methane pyrolysis with biomethane 	<ul style="list-style-type: none"> Green hydrogen is produced from zero-carbon sources and generated using renewable energy such as solar, wind, geothermal and hydroelectric power or from renewable sources such as waste biomass or biogas. While there are numerous green hydrogen technologies under development, water electrolysis remains the most established method with decades of proven commercial operation and continuous improvement in operating and capital efficiency
TURQUOISE HYDROGEN	<ul style="list-style-type: none"> Methane pyrolysis 	<ul style="list-style-type: none"> Turquoise hydrogen is produced from the cracking of natural gas using methane pyrolysis technology.

¹ IEA Hydrogen Production Facts, [https://www.iea.org/fuels-and-technologies/hydrogen], viewed on 20/02/2020

² CertifHy Project, [https://www.certifhy.eu/]

³ Department of Energy, USA – Hydrogen Production, [https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming]

05

Hydrogen Carrier Recommendations

"Due to uncertainty (not only due to cost) in the most appropriate carrier choice for Singapore, Singapore should consider several complementary receiving and infrastructure options to 2050."



Either marine transportation or pipelines will be needed to transport large volumes of hydrogen to Singapore for various downstream applications. Since hydrogen has low volumetric density at normal atmospheric temperatures, larger storage volumes will be required in shipping. Hydrogen density can be increased by both compression and liquefaction to improve storage and transportation costs. Chemical bonding hydrogen to another molecule can also increase volumetric density and improve storage and transportation costs and are referred to as hydrogen carriers.

This initial section will provide both a technical assessment of different long-distance hydrogen carrier options, in addition to discussing the merits and challenges of each option.

The key considerations which are relevant to Singapore when assessing the carriers are:

- Cost requirements;
- CO₂ emissions in Singapore;
- Expected infrastructure requirements in Singapore;
- Safety considerations;
- Technology readiness level (TRL) of each part of the supply chain, including projected improvements; and
- Potential applications.

Carrier Technologies Literature Review

A review of potential hydrogen carrier options was undertaken utilizing research from several organizations, including the National Research Foundation (NRF), Nanyang Technological University (NTU), National University of Singapore (NUS) and the Agency for Science, Technology and Research (A*STAR); as well as engagement with industry. From the review, the following hydrogen carriers were identified and assessed:

- Compressed gaseous hydrogen (supplied via pipeline);
- Liquefied hydrogen;
- Ammonia;
- Methanol;
- Liquid organic hydrogen carriers (LOHCs);
- Sorbent storage material carriers;
- Metal hydride materials (magnesium)/ complex hydrides;
- Silanes; and
- Carbon nanostructure carriers.

After thorough analysis, we conclude that sorbent storage materials, metal hydrides, silanes and carbon nanostructures are not yet suitable for large scale deployment and seaborne export and are not assessed further as part of this study.

The initial assessment shortlisted compressed gaseous hydrogen, liquefied hydrogen, ammonia, LOHCs and methanol as hydrogen carriers for further study. Supply chains for these carriers have been assessed in more detail to determine their suitability for Singapore.

Compressed Gaseous Hydrogen

Gaseous hydrogen is usually transported via pipelines, with the longest total hydrogen pipeline on record in the US at 2,608 km. Pipelines usually have a higher CAPEX, however, variations come into play depending on distance of the source to the end user as well as the amount of hydrogen being transported. As such, pipelines usually offer the most economic hydrogen transportation option. One advantage of transporting gaseous hydrogen via pipeline is that transformation and liberation stages are not needed for both carrier production and large-scale storage. However, a decrease in energy supply security becomes a disadvantage if the hydrogen comes from one source instead of multiple seaborne sources.

Cost

Due to its low volumetric density, marine shipping is more cost intensive for gaseous hydrogen compared to transportation by pipeline. To assess the viability of this option vis-à-vis the seaborne carriers, a hydrogen demand of 500 ktpa has been assumed to be transported to Singapore via pipeline at an inlet pressure of 150 barg. As the distance increases, the total pressure drop along the pipeline becomes greater than 150 barg, therefore an increase in diameter is required to keep within the 150 barg pressure at the inlet to the pipeline, resulting in a step change in costs based on distance. As such, distance plays a crucial role in determining hydrogen shipping and transportation costs. Distance associated with changes in pipeline diameter and cost is shown in Table 5.1. An industry norm of USD 150,000/km/inch is used to determine cost¹.

Table 5.1 – Pipeline Diameter Step Change with Distance and Cost

PIPELINE DIAMETER	DISTANCE (KM)	COST OF PIPELINE USD / KM
20"	0 – 750	3,000,000
24"	750 – 2,000	3,600,000
26"	2,000 – 6,000	3,900,000
28"	6,000 – 10,000	4,200,000

Figure 5.1 compares the cost of transporting hydrogen by pipeline versus seaborne liquefied hydrogen, MCH and ammonia over various distances. Storage, transformation, shipping, and liberation costs have been taken into consideration in determining carrier costs. Transporting gaseous hydrogen via pipeline is more economical than liquefied hydrogen (up to 1,000 km), ammonia (up to 925 km) and MCH (up to 7756 km). This implies that for hydrogen production locations within these distances, a pipeline is a more viable option than seaborne transportation.

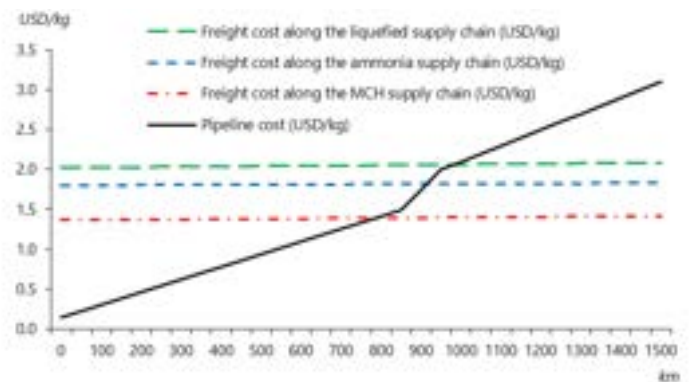
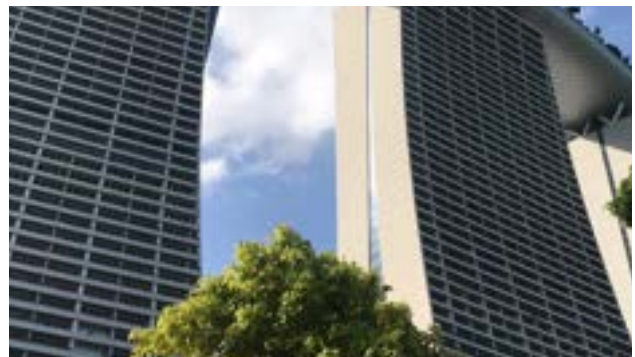


Figure 5.1 – Comparison of the Costs of Transporting Hydrogen – Pipelines vs. Liquefied Hydrogen, Ammonia & MCH

[Note: Cost figures were based on assessment done in early 2020. Since then, newer projections of cost figures are lower in absolute terms.]

Emissions

Carbon emissions from the gaseous hydrogen supply chain are derived from the gas compression stage, assuming that fossil fuel generated electricity is used for compression. The energy required to compress hydrogen to 150 barg is around 1.05 MWh / tonne hydrogen. This has an emission of 0.2 tonne CO₂ / tonne hydrogen.



¹ KBR internal data

² IEA performed a similar calculation with a crossover of 1500 km, however this calculation was performed on the basis of an onshore pipeline which has a lower CAPEX than a subsea pipeline.

Safety Considerations

Safety considerations for gaseous hydrogen are usually related to transport by subsea transmission pipeline. In general, the transport of hydrogen poses significantly more safety concerns than that of natural gas, resulting in increased safety measures and increased hydrogen deployment costs. As such, any large-scale introduction of hydrogen into Singapore's economy will likely require significant understanding of its behaviour and its safety requirements. This would allow in lockstep streamline hydrogen usage.

The following safety measures should be considered to enable safe hydrogen transportation and subsequent storage and distribution via subsea transmission pipelines.

- **Pipeline protection** – adequate pipeline protection should be provided against possible dropped objects, and any impact from third-party activities, especially in near-shore and onshore regions.
- **Material compatibility** – detailed assessment of material compatibility should be performed, especially if using existing pipelines. Diffusion of hydrogen through pipelines could lead to accumulation of hydrogen in confined spaces and subsequent ignition, resulting in fires/explosions and significant impact on personnel and asset(s).
- **Isolation** – adequate isolation, including automatic subsea isolation valves, should be considered on pipelines to minimise the amount of hydrogen released in potentially hazardous areas.
- **Leak detection** – detecting hydrogen leaks and fires can be difficult/challenging. Suitable detection measures should be implemented to allow hydrogen leaks to be detected quickly with appropriate executive actions including isolation, blowdown, and a shutdown of potential ignition sources.
- **Near-shore and onshore infrastructure** – a detailed hazard and risk assessment should be carried out, including a domino risk assessment to determine the impact of hydrogen pipeline on the risk levels in areas adjacent to the pipeline. An adequate exclusion zone should be implemented around the pipeline to minimise risk through interaction with adjacent infrastructure.
- **Pipeline routing** – pipeline routing, especially in the near-shore and onshore areas should be based on hazard and risk assessments to minimise routing through congested areas.
- **Flammability range** – hydrogen has a wide flammability range and therefore a significantly higher potential for ignition in the event of a release, compared to oil or natural gas pipelines. A detailed review should be carried out to minimise ignition sources around pipelines.
- **Explosion potential** – hydrogen is 14 times lighter than air and disperses very quickly. Depending on the physical environment, hydrogen has a higher explosion potential compared to natural gas. A hydrogen release could result in an explosion even in unconfined environments, although dissipation is a likely outcome in unconfined environments.
- **Odorization** – odorization of hydrogen gas with a compatible odorization agent should be considered to allow detection of a hydrogen leak.
- **Pipeline inspection** – periodic pipeline inspection (e.g. through pigging/smart pigging, ROVs, etc) should be carried out in line with applicable codes and standards.

Hydrogen is non-toxic compared to ammonia, methanol or LOHC. Hydrogen disperses to air when released and forms pure water from fuel cell production of electricity.

Technology Readiness Level

Gaseous hydrogen pipelines are commercially available and used extensively by hydrogen merchants worldwide. However, there are no known subsea hydrogen pipelines currently in operation. Globally, several projects have proposed the use of subsea pipelines to export hydrogen from offshore hydrogen production facilities, but these are in the early development stages. One example is Flotta Terminal HOP Project in the North Sea³. There are no major technical showstoppers envisaged for subsea hydrogen pipelines.

Potential Applications

Pure hydrogen can be used in all downstream applications without further purification since it will be transported via pipeline. This includes:

- Fuel cells for power generation and mobility;
- Hydrogen power generation;
- Industrial and manufacturing use;
- Use as a replacement fuel in the domestic gas sector;
- Use as a feedstock in carbon capture and utilisation (CCU).

³ Phase I Project Report, offshore hydrogen supply programme via industrial trials at the Flotta Terminal.

Liquefied Hydrogen

At standard temperature and pressure, hydrogen has a density of 0.09 kg/m³. When hydrogen is liquefied to -253°C at atmospheric pressure it has a density of 71 kg/m³.

Cost

The cost of liquefied hydrogen landed in Singapore from a proxy location and using a proxy method for production (PEM Electrolysis) is shown in Figure 5.2 below.

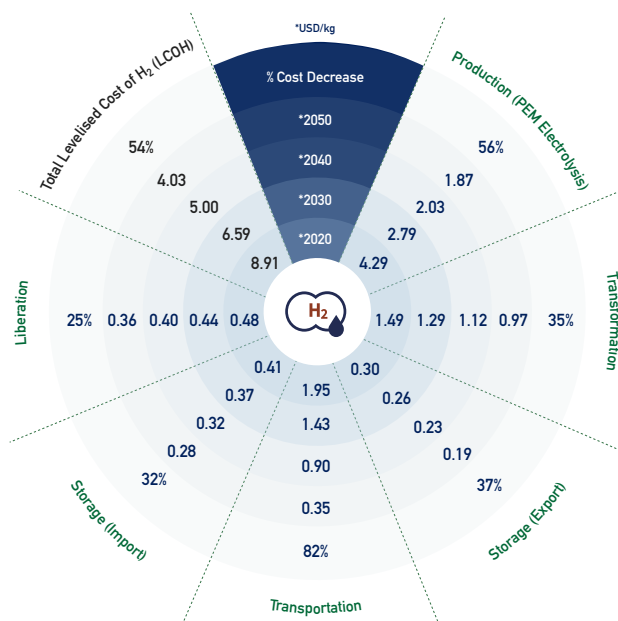


Figure 5.2 Liquefied Hydrogen Supply Chain Cost 2020 - 2050⁵

Note: Cost figures were based on assessment done in early 2020. Since then, newer projections of cost figures are lower in absolute terms.]

The landed cost of liquefied hydrogen is expected to drop by more than half over the forecast period, with the largest cost improvements in the transportation part of the supply chain projected at 82%. This part of the supply chain has the lowest TRL and therefore the largest scope for efficiency, scale and cost improvements.

Kawasaki Heavy Industries is developing two hydrogen vessels, one with a capacity of 8,000 tonnes, and the other, considered an optimum vessel, with a 11,000-tonne capacity.

This part of the supply chain carries the most risk for liquefied hydrogen as a carrier. If technology cannot be developed at scale, it will reduce liquefied hydrogen's

competitiveness to that of other carriers.

Storage costs are higher per kg of hydrogen for liquefied hydrogen than for other carriers due to the exotic material associated with hydrogen's lower temperatures

This is projected to drop by 30 – 40% over the forecast period using existing materials. There is also an opportunity to reduce this cost further if new, less expensive materials can be developed for hydrogen storage.

Emissions

Carbon emissions associated with the liquefied hydrogen supply chain are detailed in Figure 5.3. These values assume fossil fuel sources of electricity and ship propulsion. But the emissions factor could potentially be reduced to zero if renewables are used for these steps.

Moreover, if Singapore can configure regasification terminals to recover cold energy from the vaporisation process the regasification process could become carbon negative. The typical heat exchanger efficiency for low-pressure recuperation of cryogenic thermal energy is around 80% for industrial scale processing with a 10 – 15% increase in CAPEX⁴.

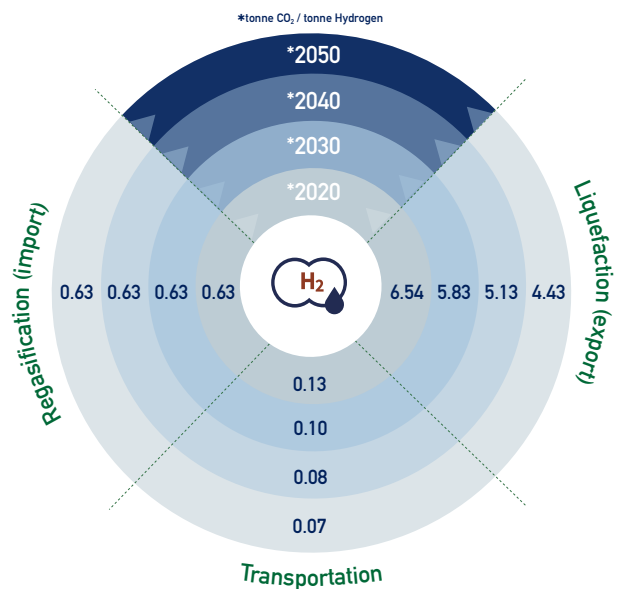


Figure 5.3 – Liquefied Hydrogen Carbon Dioxide Emissions⁵

Hydrogen liquefaction requires the most energy input along the supply chain and therefore has the largest associated emissions. However, the specific energy required to liquefy hydrogen on a per mass basis is dependent upon thermodynamic efficiencies, which

⁴ KBR Florida Space Coast Engineering Group, 17/04/2020.

⁵ Cost of regasification and liquefaction based on electricity emissions factors chosen for Singapore context

increases with the scale of the liquefaction. This means the higher the volume of hydrogen to be liquified, the lower the amount of specific energy input required for liquefaction, as shown in Figure 5.4⁵. Larger-scale liquefaction projects may have a lower energy requirement and therefore lower emissions by 2050. This may also improve the landed cost of hydrogen, thus increasing the competitiveness of liquefied hydrogen as an energy carrier.

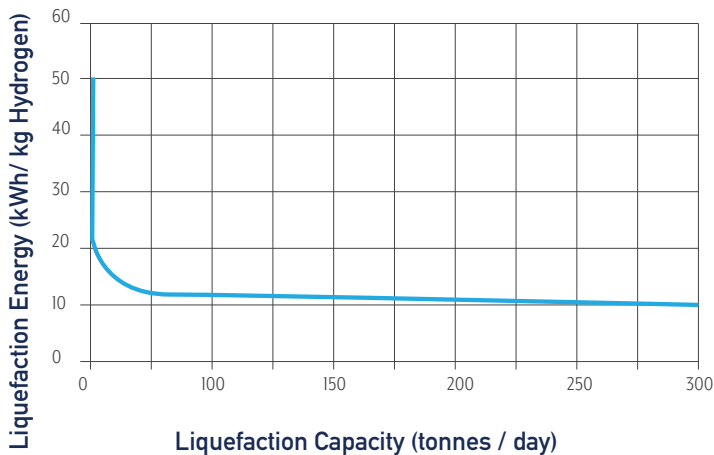


Figure 5.4 – Typical Energy Requirements for the Liquefaction of Hydrogen⁶

Safety Considerations

Table 5.2 summarises the key safety issues pertaining to hydrogen and are compared to those for natural gas. In general, hydrogen poses significantly more safety challenges than natural gas. This means that hydrogen-related infrastructure is likely to require increased safety measures, which likely leads to higher costs required to deploy the fuel. Although hydrogen is already deployed extensively in industrial applications with associated safety protocols and safety procedures, the safety aspects of hydrogen are more complex and unfamiliar compared to natural gas, particularly around safety testing. Introduction of hydrogen to the economy at a large scale will require significant investment to understand the behaviour of and therefore safety requirements for the fuel.

A number of design and risk analysis/management measures to enable the safe use of hydrogen are listed below.

- Hydrogen's calculated safety distances will be larger compared to other fuels due to its properties as well as its higher operating pressure;
- Control of ignition sources;
- Good ventilation (natural ventilation or mechanical ventilation);
- Implementation of detection and control systems;
- Measures to prevent hydrogen accumulation;
- Limit plant/site congestion;
- Hazard and risk analysis, assess consequences from potential fire/explosion events and calculate the risk associated with hydrogen infrastructure. The analysis should include assessment of:
 - Fire events – extent/duration of jet fires and extent of flammable gas dispersion clouds to assess the impact on infrastructure and personnel located both outdoors and indoors; and
 - Explosion events – extent of explosion overpressures to assess impact on infrastructure and personnel located both outdoors and indoors.

⁶ Connelly, Elizabeth et al. (2019) Current Status of Hydrogen Liquefaction Costs. Department of Energy Hydrogen and Fuel Cells Program Record.

Table 5.2 – Hydrogen Safety Considerations

Hydrogen Safety Risk	Natural Gas Risk	Risk Increase or Decrease
If there is a delayed ignition, there is potential for hydrogen to detonate with explosion overpressures > 10 bar.	Methane does not detonate under general process plant conditions and only has explosion overpressures < 1 barg.	Increase in risk to significant loss of life and property.
Hydrogen is extremely flammable and has potential to spontaneously ignite or ignite by static discharge or friction at a relatively low velocity. The minimum ignition energy for ignition of hydrogen (0.02 MJ).	Methane minimum ignition energy is 0.2 MJ.	Increase in the risk of leaked hydrogen finding an ignition source. Increase in the number of scenarios that could cause an ignition source.
Hydrogen burns with an almost invisible flame with low radiant heat, furthermore hydrogen cannot be odourised with mercaptans. This makes ignitions hard to detect with the naked eye.	Methane burns with a blue flame and can be odourised for leak detection.	Increase in the risk of hydrogen leak and ignition going undetected.
Hydrogen is the lightest gas and therefore has high diffusability (i.e. hydrogen can pass through thin membrane materials).	Methane is a larger molecule and is therefore less likely to diffuse through membrane materials.	Increase risk of hydrogen leak and special membrane materials required for construction.
Mercaptans cannot currently be employed with hydrogen as their Sulphur atoms bind irreversibly to the catalyst in the fuel cell membrane and rapidly halt its operation.	Mercaptans and thiophanes may be used to stench natural gas and liquefied petroleum gas (LPG), thereby greatly increasing the likelihood of early leak detection.	Increase risk of leak detection if a suitable odourisation chemical is not found for hydrogen.

Technology Readiness Level

The TRL of each part of the liquefied hydrogen supply chain is commercially mature with the exception of liquefied hydrogen seaborne transportation. Transportation TRL is the lowest in the supply chain and requires the most RD&D focus to enable liquefied hydrogen as a carrier. In particular, exotic materials required due to extreme operating conditions for liquefied hydrogen drive a higher transportation CAPEX, making it very costly on a comparative basis. Based on the review listed above and discussions with stakeholders, 2030 can be given as a projected timeline for commercialisation. The first pilot trial ship will be constructed sometime this year,

however based on pilot outcomes and increased interest from other stakeholders that time frame could be pushed forward.

Potential Applications

Due to the purity of hydrogen after regasification, hydrogen can be used in all downstream applications without further purification. This includes:

- Fuel cells for power generation and mobility;
- Hydrogen power generation;

- Industrial and manufacturing use;
- Use as a replacement fuel in the domestic gas sector;
- Use as a feedstock in carbon capture and utilisation (CCU).

Ammonia

Ammonia has a hydrogen density of 17.8wt% (12.1vol%) and can be stored as a liquid at -33°C under atmospheric pressure. Ammonia is the second most widely produced chemical commodity, with a commercially mature production and shipping supply chain. It has a production rate of over 180 million tonnes per year and is mainly used in the agricultural industry. If used as an energy carrier, ammonia can either be used directly as a fuel (where applicable) or cracked back into nitrogen and hydrogen, its original components. Ammonia is a chemical consisting of one atom of nitrogen and three atoms of hydrogen.

Cost

Figure 5.5 shows the cost of landed hydrogen in Singapore using ammonia as the carrier.

Emissions

Figure 5.6 details carbon emissions associated with the ammonia supply chain. These values assume the use of fossil fuels for electricity and ship propulsion. However, the emissions factor could potentially decrease to zero if renewable energy is used.

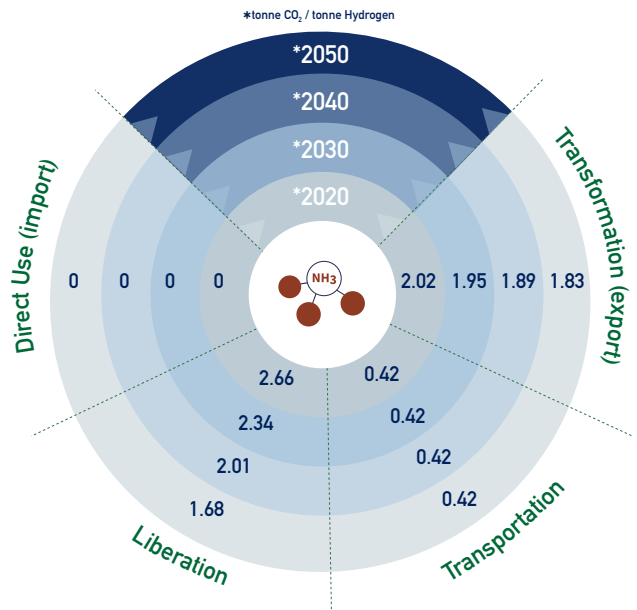


Figure 5.6 – Ammonia Supply Chain Carbon Dioxide Emissions

This analysis assumes the use of the conventional Haber-Bosch process, widely used for transformation into ammonia in production plants worldwide. As the ammonia production process is a relatively mature technology, there are no significant improvements in process efficiency expected across the forecast period.

The transportation phase of an ammonia carrier would involve a very large gas carrier (VLGC) or medium gas carrier (MGC) to transport the cargo. However, using fuel oil as a transportation fuel would contribute to its CO₂ emissions profile. The size of the transportation vessel has already been optimised by the industry, wherein VLGC and MGC are mature vessel sizes in the LPG/ammonia freight industry. Hence, no further economies of scale on fuel usage to tonne carried is expected.

The liberation of hydrogen from ammonia is currently a low TRL technology which requires a significant amount of heat and energy. However, the energy requirements for this process is predicted to fall with the current trajectory of technological developments. Directly burning ammonia produces no CO₂ emissions, however, it could increase nitrogen oxides (NO_x) emissions, which would need to be tightly controlled.

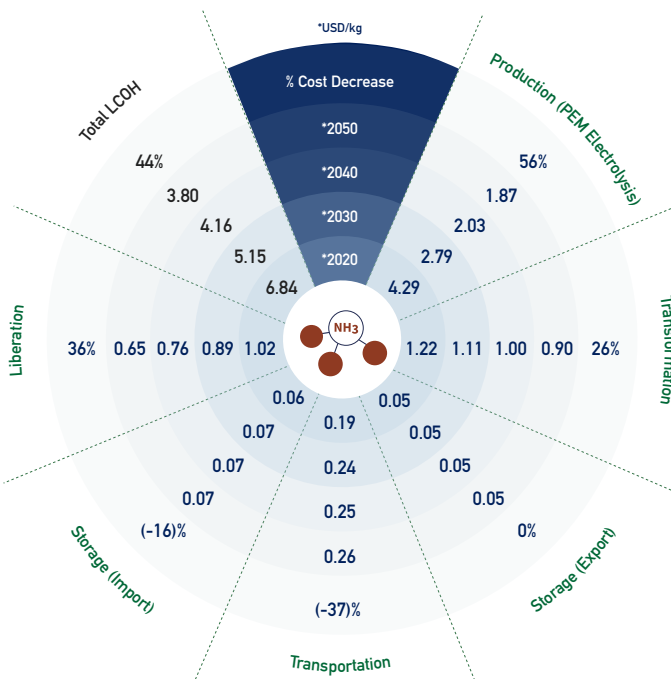


Figure 5.5 – Ammonia Supply Chain Cost 2020 - 2050⁷

⁷ Leighty, Bill (2006) Costs of Delivered Energy from Large-scale, Diverse, Stranded, Renewable Resources, Transmitted and Firmed as Electricity, Gaseous Hydrogen, and Ammonia. Ammonia: Key to US Energy Independence
 Silversand, F. (2002) Catalytic Heat Exchangers for small-scale production of hydrogen - feasibility study. Svenskt Gastekniskt Center (above as guides)

Safety Considerations

Table 5.3 summarises key ammonia safety issues compared to natural gas, including changes in risk profiles. Overall, it is likely that the infrastructure and operating procedures from ammonia will likely require increased safety measures, which in turn will increase ammonia deployment costs. Moreover, since ammonia is a toxic, flammable, and corrosive compound, it involves more safety considerations than other carriers.

Table 5.3 – Ammonia Safety Considerations

Ammonia Safety Risk	Natural Gas Risk	Risk Increase or Decrease
Ammonia is a toxic gas and exposure to 3500-6400 ppm for 1 - 2 hours can be life threatening.	Natural gas is non-toxic and can only cause harm to humans in non-ventilated areas.	Risk increase due to exposure to ammonia in non-confined spaces.
Ammonia has a strong odour.	Natural gas is odourless but is odourised with mercaptans for detection purposes.	No change.
Anhydrous ammonia will evaporate vigorously causing toxic gas to enter the air if it is accidentally released from storage.	Natural gas is non-toxic so the vaporisation of LNG if it is released has no increased risk.	Risk increase of exposure to toxic gases in the event of an ammonia release.
Ammonia reacts with acids.	Natural gas is non-reactive.	Risk increase when exposed to acids. This will increase the safety distances and measures when ammonia pipeline routings are in the vicinity of facilities which store/produce/use acids.
Ammonia is not highly flammable with a flammability of 15% by volume in air.	The flammability range of methane is between 5% and 15% by volume in air.	Risk decrease of flammability in air.
Ammonia is corrosive due to its alkaline properties.	Natural gas is non-corrosive.	Risk increase , particularly pertaining to materials of construction for ammonia.

Technology Readiness Level

The TRL for each part of the ammonia supply chain is commercially mature with the exception of ammonia cracking. Presently, ammonia cracking technology is at a TRL of 3 to 6, while significant RD&D is currently being undertaken to develop high-purity cracking technologies with cost-effective hydrogen purification membranes.

There are two pathways for ammonia cracking to produce hydrogen:

- **Centralised ammonia cracking** – the ammonia is fed through an ammonia cracker at a central location and is transported through hydrogen pipelines or as high-pressure hydrogen cylinders to end users such as hydrogen fuelling stations and industry.
- **Decentralised ammonia cracking** – ammonia is transported as liquid ammonia through tankers or pipeline where it is cracked, at the customers site, using a membrane reactor.

Stakeholders that are developing the technology have thus far been focused on decentralized ammonia cracking in various regions, including Europe, where hydrogen is being produced in closer proximity to end users.

Centralised cracking is the most appropriate option for Singapore, however, since RD&D efforts are not currently focused on this area, a projected timeline for ammonia commercialisation has been placed at 2035. This timeline could be pushed forward if more emphasis is given to develop large-scale centralized ammonia cracking.

Potential Applications

Ammonia can be used directly as a fuel or cracked to liberate the hydrogen. For example, in coal fired power generation, ammonia can be used directly; and blended with coal in combustion to reduce the CO₂ emissions of the process. Currently, ammonia is used in coal-fired plants for power generation in Japan, which is increasing green and blue hydrogen demand in the APAC region. However, given that this case is not applicable for Singapore, and due to safety concerns with NO_x emissions, and the nascent nature of direct combustion of ammonia in GTs, the use of hydrogen in GTs will likely be more relevant for Singapore.

Depending on the end-use application and the volumes of ammonia being imported into Singapore either centralised or decentralised cracking may be appropriate for deployment in Singapore. The advantages and disadvantages of each pathway in the Singaporean context is detailed in Table 5.4.

Table 5.4 - Advantages and Disadvantages of Ammonia Cracking Pathways

Ammonia Cracking	Advantages	Disadvantages
Centralised	<ul style="list-style-type: none"> ■ Enables the containment of toxic ammonia in industrial facilities. ■ Reduces the safety risks associated with transporting/handling ammonia. 	<ul style="list-style-type: none"> ■ No RD&D focus currently on centralised cracking. ■ Based on preliminary research from stakeholders, centralised cracking is more expensive than decentralised for distances more than 100km⁸.
Decentralised	<ul style="list-style-type: none"> ■ Integration of the reaction and separation process steps lower operating temperatures. ■ On-site hydrogen recovery and supply, and a simplistic design with significantly lower number of operating units and balance of plant (BoP). 	<ul style="list-style-type: none"> ■ Toxic ammonia transported and distributed in built-up urban areas. ■ Increase in ammonia storage in Singapore required.

The companies investing RD&D into ammonia cracking technologies include:

- Engie;
- Mitsubishi Heavy Industries; and
- Fortescue Metals Group (FMG).

Besides the use as a fuel domestically, ammonia as a carrier for hydrogen presents a further opportunity for direct use as a carbon-free bunkering fuel, this is discussed in further detail in Section 12.

⁸ Engie Lab Singapore, Stakeholder Interview, May 2020

Liquid Organic Hydrogen Carriers

LOHCs are liquids or low-melting solids that can be reversibly hydrogenated and dehydrogenated at elevated temperatures in the presence of catalyst⁹. It has a weight of 6% hydrogen which is the lowest of all the carriers studied. LOHC technology utilises the chemical bonding of hydrogen to aromatic hydrocarbons or heterocyclic compounds via catalytic reactions. The benefit of LOHCs is that the carrier structure remains untouched and there is no requirement for generation of the carrier for every cycle.

The process starts with hydrogen being loaded onto a carrier molecule through an exothermic hydrogenation reaction. This new compound holds the hydrogen and is a liquid at ambient temperature and pressure, which makes road and sea transportation easier. Upon its arrival at the destination, the process is reversed, using an endothermic dehydrogenation process resulting in hydrogen being liberated from the carrier molecule. The carrier compound can then be recycled for future use as a hydrogen carrier. In this study, the LOHCs methylcyclohexane (MCH) and dibenzyltoluene (DBT) are considered for further analysis. A comparison of the properties of the two carriers are shown in Table 5.5.

Table 5.5 - LOHC Properties

DESCRIPTION	TOLUENE – MCH	DIBENZYL – TOLUENE (DBT)
Molecular Weight	98.19	272.38
Density (kg /m ³)	769	1040
Boiling point (°C)	101	390
Hydrogen density (wt%)	6.16	6.20
Hydrogen release temperature (°C)	200 to 400	300
Regeneration temperature (°C)	100 to 200	150

Cost

Figure 5.7 shows the landed cost of hydrogen in Singapore using DBT (values would be similar for MCH).

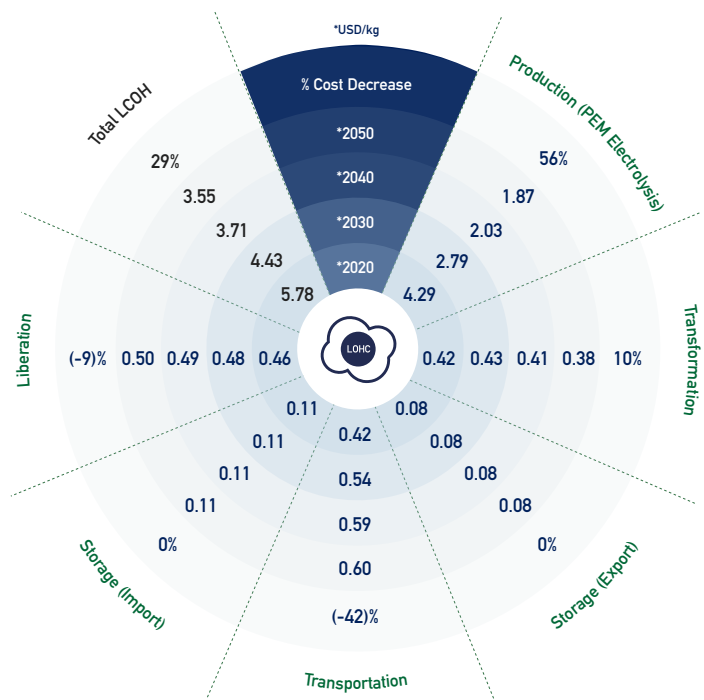


Figure 5.7 - LOHC Supply Chain Cost 2020 - 2050^{9,10}

[Note: Cost figures were based on assessment done in early 2020. Since then, newer projections of cost figures are lower in absolute terms.]

Hydrogenating and dehydrogenating LOHCs have lower energy requirements, resulting in an overall lower cost than liquefied hydrogen and ammonia. Despite the low density of hydrogen carried by an LOHC and the requirement to ship the dehydrogenated DBT back to its original destination. Efficiency improvements within this process over the forecast period are not envisaged. Projected bunker fuel and energy price increases over the forecast period will cause a corresponding increase in both transportation and liberation costs. If LOHCs, with a higher hydrogen content can be developed, they have significant potential to disrupt the supply chain and reduce the cost of landed hydrogen into Singapore.

Emissions

Carbon emissions associated with the LOHC supply chain are detailed in Figure 5.8. Emissions were calculated using DBT as the LOHC. These values assume fossil fuel sources of electricity and ship propulsion; for LOHC it is assumed that, once the hydrogen is liberated, the DBT will have to be transported back to the place of origin. Therefore, this is

⁹ IEA (2019) The Future of Hydrogen <https://www.iea.org/reports/the-future-of-hydrogen>

¹⁰ Papadias, D.D., Peng, J-K, Ahluwalia, R.K. (2018) Chemical Carrier Concepts for Hydrogen Delivery [<https://www.energy.gov/sites/prod/files/2018/10/f56/fcto-infrastructure-workshop-2018-31-ahluwalia.pdf>] (above as guides)

accounted for within CO₂ emissions. For other carriers, it is assumed that the cargo delivery is one way. Emissions can be reduced to zero by using renewable energy sources for ship propulsion and electricity.

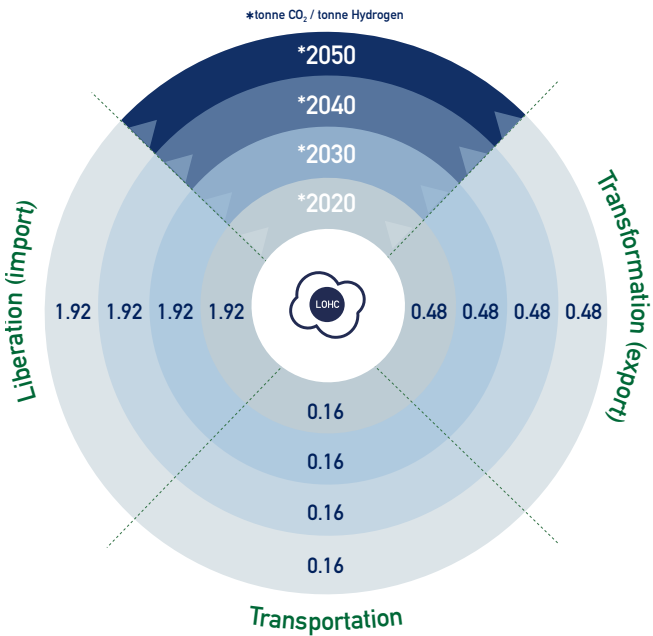


Figure 5.8 - LOHC Supply Chain Carbon Dioxide Emissions

Safety Considerations

Both MCH and DBT exist in liquid form with minimal handling issues and exhibit the same fluid behaviours as liquid hydrocarbons. The exceptions where LOHCs have safety considerations are detailed in Table 5.6. Generally, MCH is more dangerous than DBT since it is toxic and flammable, however LOHCs are safer than the other carriers in their liquid forms. LOHCs are not currently handled or transported in large quantities. Since LOHCs integrate well with existing liquid hydrocarbon infrastructure, it is not envisaged that they will not contribute to significantly higher safety constraints.

Table 5.6 – LOHC Safety Risks

LOHC Safety Risk	Toluene – MCH	Risk Increase or Decrease
MCH is toxic ¹¹ .	Natural gas is non-toxic and can only cause harm to humans in non-ventilated areas.	Risk increase if MCH is ignited and gaseous fumes released into atmosphere for inhalation.
DBT is non-toxic.		Neutral.
Low flammability like diesel (0.6%).	Natural gas has a higher flammability.	Decreased risk for LOHCs.
MCH is non-explosive as a liquid, however vapour-air mixtures are explosive.	A release of natural gas results in an explosion only in confined or congested environments.	Decreased risk for LOHCs as handled as a liquid.
DBT is non-explosive.		Decreased.

Technology Readiness Level

Hydrogenation of LOHCs is a commercial process, while the respective dehydrogenation processes are not as common. The RD&D focus areas for LOHCs at large scale globally are:

- Increasing the dehydrogenation catalyst efficiency; and
- Increasing the purity of hydrogen liberated.

A dehydrogenation temperature of 400°C can result in catalyst deactivation due to coke deposition on the fixed-bed reactor and the development of stable dehydrogenation catalysts when sufficient activity is necessary. Since several companies, including Chiyoda and Hydrogenius, are developing and commercialising this technology, it is expected to reach commercial level by 2025.

Potential Applications

Hydrogen liberated from LOHCs has a 99.97% purity rate, which is below that required for fuel cells at (99.999%). Therefore, unless purification is applied, the potential applications for LOHCs would be limited to:

¹¹ Hurskainen, Markus (2019). Liquid organic hydrogen carriers (LOHC).

- Power generation (both industrial and centralised); and
- Town gas.

It should be noted that the energy required for hydrogen purification is not included in emission calculations in this report.

Methanol

Methanol is a commodity chemical widely traded across the world and can be transported at ambient conditions. Traditionally, methanol is produced from natural gas by reforming the gas with steam and then converting and distilling the resulting synthesised gas mixture to create pure methanol. This production method is carbon intensive. There are other less carbon intensive routes to produce methanol including utilising CCUS on the traditional process, as well as producing synthetic methanol from CO₂ and low-carbon hydrogen. Synthetic methanol technology is in its nascent stages and large volumes of both CO₂ and green hydrogen are required, neither of which have mature supply chains. In addition large amounts of energy are needed to produce methanol. For this analysis, the synthetic methanol route will be assessed to ensure a like-for-like comparison of hydrogen production with other carriers.

Cost

Figure 5.9 shows the landed cost of hydrogen in Singapore using synthetic methanol.

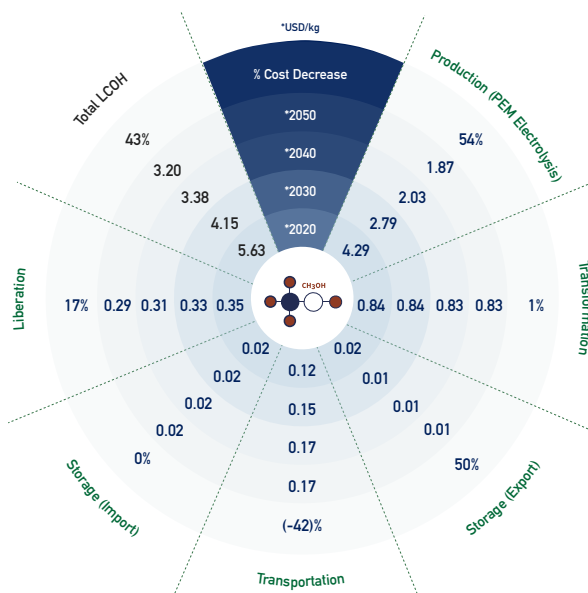


Figure 5.9 – Methanol Supply Chain Cost 2020 - 2050

[Note: Cost figures were based on assessment done in early 2020. Since then, newer projections of cost figures are lower in absolute terms.]

The methanol supply chain provides the lowest cost of all the carriers due to the maturity of the supply chain and the ease of transporting and storing the compound. However, to make the methanol supply chain more carbon neutral, two nascent markets (green hydrogen production and carbon capture and utilisation) must mature both technically and economically. This will also allow viable synthetic methanol production. Furthermore, this calculation currently assumes that the CO₂ required for synthetic methanol production is free. Making carbon capture and utilisation (CCU) viable will likely incur more cost, thereby also increasing transformation costs.

Emissions

Emissions from the methanol supply chain are detailed in Figure 5.10. This only includes emissions from the energy required to produce, transport and liberate the hydrogen from methanol and does not take into account energy required to produce synthetic methanol. When hydrogen is liberated from methanol, CO₂ emissions are released within Singapore¹².

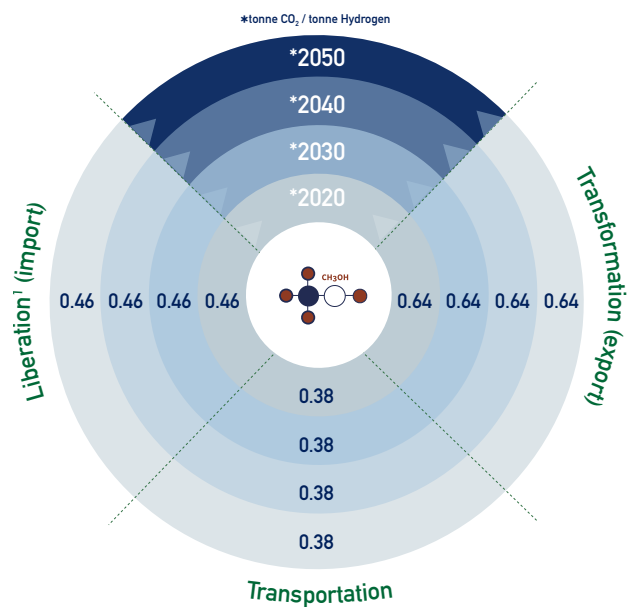


Figure 5.10 – Methanol Supply Chain Carbon Dioxide Emissions

Notes:

¹²The liberation emissions only accounts for the energy required to liberate the hydrogen and not the emissions associated with release of the CO₂ molecule itself. It is assumed that the CO₂ used to produce synthetic methanol is captured and therefore is not accounted for when released via liberation. If methanol is produced through a different, non-renewable route then the emissions in Singapore would have an additional 5.07 tonne CO₂ / tonne of hydrogen to account for the release of the CO₂ molecule.

¹² CO₂ captured from the atmosphere for methanol production is not considered in Singapore's GHG inventory, however CO₂ captured from an emission stream for methanol production will be abated at the source and introduced again when the methanol is burned in Singapore.

Safety Considerations

Methanol is a familiar chemical with widespread knowledge of behaviours and handling and appropriate safety procedures. Key safety considerations are detailed in Table 5.7.

Table 5.7 – Methanol Safety Considerations

Methanol Safety Risk	Natural Gas Risk	Risk Increase or Decrease
Low flammability.	Natural gas has a higher flammability.	Decreased risk for methanol.
Methanol is denser than air so will pool rather than disperse.	Natural gas disperses into the atmosphere and can build up in confined spaces.	Risk neutral as dispersed pool of methanol can be noticed more easily, however is more likely to alight as higher concentration in a small space.
Methanol burns with a colourless flame.	Methane burns with a blue flame.	Risk increase of methanol fire going undetected.
Methanol is toxic and can cause harm to life.	Natural gas is non-toxic and can only cause harm to humans in non-ventilated areas.	Risk increase if methanol is ignited and gaseous fumes released into atmosphere for inhalation.

Technology Readiness Level

The methanol supply chain is mature except for synthetic methanol production, which requires two low TRL processes (green hydrogen production and carbon capture) to mature simultaneously. The projected timeline for deployment of synthetic methanol production is 2040.

Potential Applications

Once methanol has reached its intended destination, it can be decomposed to release hydrogen or used directly as power generation fuel. If hydrogen is released due to decomposition, then it could be used in all downstream applications in Singapore.

Singapore Infrastructure Requirements per Carrier

Required receiving and storage infrastructure within Singapore will vary depending on selected carriers as well as hydrogen volume levels.

Cargo Frequency

Figure 5.11 shows the daily cargo frequency in Singapore for each carrier as a function of imported hydrogen volume. It is estimated that each cargo will take around 12 hours to dock, unload and depart from jetty loading areas. It is assumed that the maximum number of cargoes that could be received into Singapore per day is two since a jetty can only unload one cargo at a time. Therefore, given these unloading constraints, carriers may be limited. From a cargo receiving perspective, LOHC is feasible for volumes less than 1,000 ktpa, while methanol and ammonia can be utilised for hydrogen

volumes below 2,000 ktpa and 3,000 ktpa respectively. Liquefied hydrogen requires the least number of cargoes and plateaus around two cargoes per day up to 8,500 ktpa. Therefore, as hydrogen demand increases, cargo frequency may affect carrier feasibility.

required at this scale. Maximum storage volumes in use today equal 10,000m³. RD&D and testing with large cylinders, up to 50,000m³ is currently being conducted.

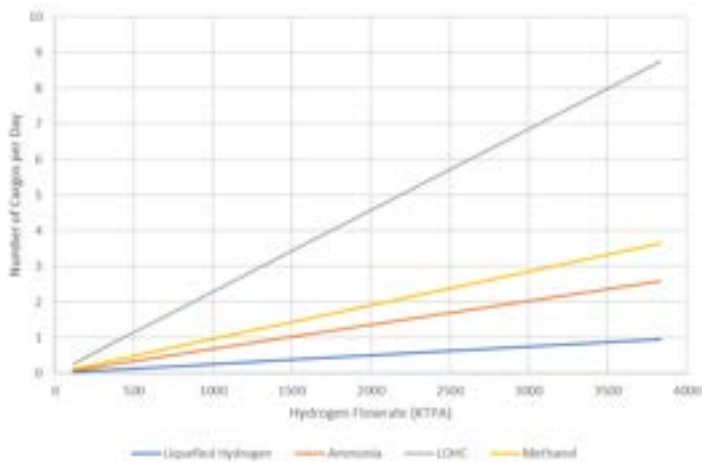


Figure 5.11 – Carrier Cargoes into Singapore per day¹³

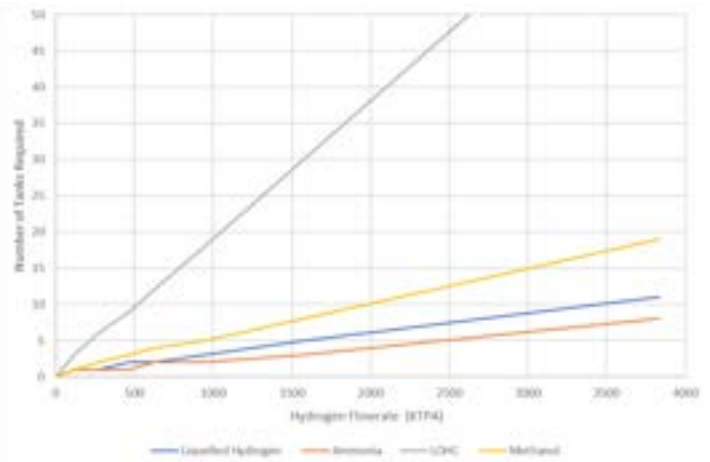


Figure 5.12 – Number of Storage Tanks Required in Singapore per carrier vs Increasing Hydrogen Volumes

Storage Requirements

Figure 5.12 shows the number of tanks required in Singapore for each carrier as imported hydrogen volumes increases. Figure 5.13 shows the corresponding footprint requirement to accommodate storage facilities (excluding regasification or hydrogen liberation facilities).

Both figures show that LOHCs have the largest storage and footprint requirements and increase at a steeper gradient than the other carriers as the volume of hydrogen increases. Furthermore, once the hydrogen is liberated, the dehydrogenated toluene will need to be shipped back to its source. Consequently, there may need to be additional infrastructure for LOHC, liberated hydrogen and toluene depending on supply chain logistics. However, LOHCs also have the highest compatibility for integration into Singapore’s existing infrastructure as they can be stored at ambient conditions, unlike other carriers.

Ammonia requires the least number of storage tanks and as such has the smallest land footprint. Like LOHCs, there is an opportunity to repurpose existing ammonia infrastructure for ammonia storage within Singapore, and this will be elaborated on in Section 13.

Methanol and liquefied hydrogen have similar footprint requirements despite more tank storage requirements for methanol. This is because liquefied hydrogen tanks have a larger footprint, estimated to be around 50,000m³ by 2030. Liquefied hydrogen storage has not yet been

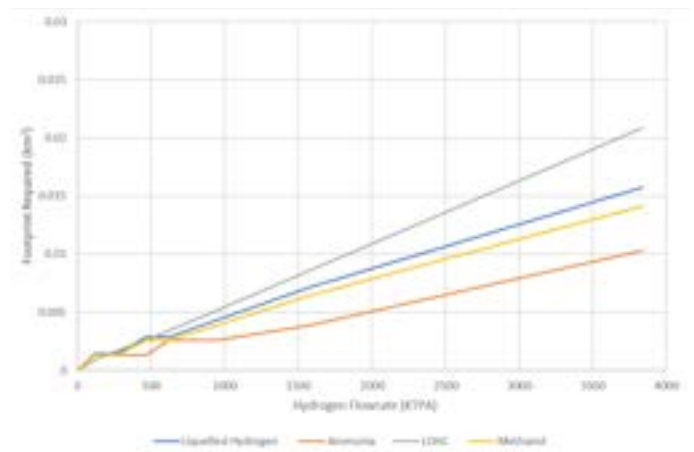


Figure 5.13 – Land Footprint Required in Singapore per carrier vs Increasing Hydrogen Volumes

¹³ DBT used for MCH calculations.

Conclusions and Recommendations

Figure 5.14 shows predicted cost improvements of each carrier supply chain from 2020 – 2050.

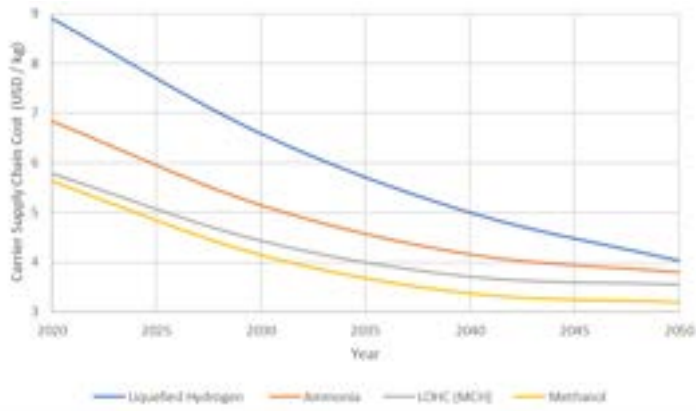


Figure 5.14 – Predicted Cost Improvements of Each Carrier Supply Chain From 2020 – 2050

Based on the uncertainty around the most appropriate and cost-effective carrier for Singapore, there may be a need to develop a number of complementary infrastructure options to receive hydrogen over the period to 2050. Each carrier has its own set of advantages and challenges to meet Singapore-specific constraints, safety and risk profiles, timelines for deployment, and infrastructure requirements. As mentioned, these vary with Singapore's potential hydrogen demand.

Key challenges and barriers for liquefied hydrogen as a carrier are:

- The highest landed costs of the carriers primarily attributed to the requirement for new and costly infrastructure to support liquefied hydrogen storage and seaborne transport which is a relatively nascent technology.
- Liquefied hydrogen poses significantly more safety challenges than natural gas. This means that hydrogen-related infrastructure is likely to require more stringent safety measures, which likely leads to higher costs.

Key advantages and opportunities for liquefied hydrogen as a carrier are:

- The supply chain provides the most opportunity for technological improvement and reduction in cost due to scale and efficiency improvements as it is the least mature supply chain carrier.
- The cold energy recovery from liquefied hydrogen could be deployed to further increase the economic attractiveness and further reduce CO₂ emissions.
- For large-scale hydrogen demand (greater than 3,000 ktpa), liquefied hydrogen has the lowest cargo frequency and second-lowest storage and footprint requirements for Singapore after ammonia.

If the cost challenges associated with liquefied hydrogen can be overcome through RD&D and investment in liquefaction technologies, liquefied hydrogen could be considered as a long-term carrier for Singapore.

Key challenges and barriers for ammonia as a carrier are:

- It is the second-highest landed price after liquefied hydrogen. As ammonia is already a widely traded commodity with a market price, it will be challenging to differentiate between and justify the high cost of green and conventional ammonia.
- Downstream applications and ammonia cracking technologies have a longer commercialisation timeline than the other carriers, except for methanol. Beyond simple combustion in coal-fired plants in other locations, such as Japan, downstream technologies are not currently commercialised for ammonia, while large-scale centralised ammonia cracking is not currently being developed. For the Singapore-specific case, it is more likely that pure hydrogen will be required for domestic applications. As such, ammonia cracking technology deployment is important for its deployment in Singapore.
- Environmental and safety risks for handling and transporting ammonia in Singapore are significantly higher compared to existing infrastructure. Consequently, this remains a major deployment challenge.

Key advantages and opportunities for ammonia as a carrier are:

- The ammonia supply chain is mature compared to liquefied hydrogen, while ammonia is a widely-traded commodity with mature safety standards and operational handling procedures.
- Ammonia may be able to integrate into the existing infrastructure pending engineering studies, however since it is corrosive it may require new facilities.
- Ammonia may play a role in the global transition of bunkering fuel, in which Singapore may have a unique role to play since it is one of the top bunkering hubs in the world.

Key challenges and barriers for LOHCs as a carrier are:

- At larger import volumes (greater than 1,000 ktpa) of hydrogen, cargo logistics and storage requirements of LOHC become challenging.
- Large-scale deployment of the supply chain has not yet been fully tested and may encounter some issues in chemical availability in case of widespread deployment.
- Hydrogen liberated from LOHCs requires further purification to be deployed into fuel cell applications.

Key advantages and opportunities for LOHCs as a carrier are:

- The LOHC supply chain is mature compared to liquefied hydrogen. LOHCs are also widely traded commodities with mature safety standards and operational handling procedures.
- LOHCs are the least energy-intensive carrier for hydrogenation and dehydrogenation.
- LOHCs provide the lowest landed cost of hydrogen, besides methanol, despite carrying the lowest hydrogen content.
- LOHCs can integrate into existing infrastructure and do not pose significant safety barriers compared to natural gas.

Key challenges and barriers for methanol as a carrier are:

- Methanol production using a carbon-intensive route will contribute to Singapore's CO₂ emission problems. However, if it is produced through renewable CO₂ and hydrogen or with carbon capture, emissions in Singapore would be more comparable to other carriers.
- Synthetic methanol has the longest deployment timeline due to the reliance on two nascent supply chains maturing simultaneously, CCU and green hydrogen.

Key advantages and opportunities for methanol as a carrier are:

- Methanol has the potential to integrate well into Singapore's existing infrastructure.
- Methanol has the lowest landed cost of the carriers.

Based on this assessment of carriers, it is recommended:

- Transporting gaseous hydrogen via a pipeline is more economical than liquefied hydrogen (up to 1,000 km), ammonia (up to 925 km) and MCH (up to 775 km) and should be considered as a viable option vis-à-vis transportation by sea with other carrier options.
- Liquefied hydrogen supply chain provides the most opportunity for technological improvement and reduction in cost due to scale and efficiency improvements as it is the least mature liquid hydrogen carrier when looking along the entire supply chain.
- Reducing liquefied hydrogen storage and transport technology costs significantly could provide Singapore with long-term carrier solutions. This is particularly true for large hydrogen volumes given their storage and cargo logistics feasibility. However, this will depend on imported hydrogen volumes. Ammonia could also be an appropriate long-term carrier solution for Singapore if cargo sizes are increased and centralised cracking technology developed.

- In the short term, LOHCs and ammonia are feasible hydrogen import carriers. Existing assets can be repurposed for LOHC storage, which will help to enable domestic sectors transition while also reducing the risk of stranded assets if hydrogen is not adopted eventually.
- If centralised ammonia and methanol cracking is not pursued for RD&D development, then decentralised cracking may be appropriate for use in Singapore maritime industry. This is primarily due to the transition of bunkering fuels for international shipping towards low-carbon alternatives. Decentralised cracking can be deployed for port and marine propulsion operations, while the infrastructure can be developed, taking into

consideration ammonia or methanol as bunkering fuel. Furthermore, the environmental and safety risks for the handling and transporting ammonia around Singapore are significantly higher than what the existing infrastructure may support, while posing a major challenge for its deployment.

RD&D Focus Areas

Each carrier supply chain has RD&D areas which require focus and investment to accelerate hydrogen deployment. The general RD&D areas for each supply chain are shown in Table 5.8. Recommendations RD&D areas specific to Singapore will be presented in Section 16 after assessing these areas against Singapore's RD&D capabilities and strengths.

Table 5.8 – RD&D Focus Areas for Hydrogen Carrier

Technology	Barrier / Gap	Current TRL
Storage Materials for Liquefied Hydrogen	Liquefied hydrogen storage vessels are typically of carbon steel construction with a stainless-steel interior lining. More exotic materials are required elsewhere in an liquefied hydrogen facility due to extreme operating conditions, which drives high CAPEX.	5 ¹⁶
Cold Energy Recovery	Cold energy recovery is not currently done in Singapore for LNG due to configuration. Off-takers for cold energy to be identified.	4
Ammonia Cracking	No proven commercially available technology.	5
LOHC	Improving de-hydrogenation energy/ hydrogen purity	4-6

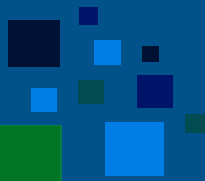


¹⁶ Due to unproven scale-up from 5,000m³ to 50,000m³ spheres.

06

Sources of Hydrogen Imports

"There appears to be enough interest and project development globally for Singapore to achieve a secure and reliable mix of hydrogen energy imports."



Nations are currently exploring the possibility of producing and exporting hydrogen to satisfy growing clean energy demand. This is driving the development of several demonstration and commercial stage hydrogen production and export projects where developers are studying the feasibility of global hydrogen supply chains. These projects have the potential to be developed into commercial scale export facilities upon successful completion of the demonstration stage. This will depend on a number of technical and economic factors such as:

- Technology readiness;
- Ability to scale;
- Off-take agreements;
- End user acceptance;
- Policy and government support; and
- Project financing.

Nations including Australia, Malaysia, New Zealand, Chile, Norway, Russia, the United Arab Emirates (UAE), Saudi Arabia and Oman have expressed interest in hydrogen export economies.

As a nation with limited natural resources, Singapore is dependent on energy imports, particularly natural gas, to sustain its economic activity. Therefore, it is vital that several import countries are considered to enhance supply security. Energy security is defined by the International Energy Agency (IEA) as the uninterrupted supply of energy to a nation at an affordable price. Energy security includes both the supply of energy from importing nations and its delivery. It can be divided into the following four categories¹:

- Availability - ensures energy supplies are available and accessible in appropriate quantities.
- Affordability - aims to deliver these resources at affordable prices and with reduced volatility.
- Accessibility - ensures all citizens and industries have access to energy.
- Acceptability - improves public perception of energy sources from an environmental standpoint.

The review process to identify potential import sources was split into two phases:

Table 6.1 – Potential Import Sources Review Phases

PHASE ONE	PHASE TWO
<p>An assessment framework was developed to score various projects and systematically ranked them according to a range of criteria. The framework considered the following:</p> <ul style="list-style-type: none"> ■ Proximity; ■ Ease of doing business ranking; ■ Existing trade relations; ■ Export potential; and ■ Energy security. 	<p>The top 12 sources identified in the first phase were qualitatively and quantitatively analysed further, in consultation with the project developers and key stakeholders to produce detailed information on the following:</p> <ul style="list-style-type: none"> ■ Technology; ■ Landed cost; ■ Project economics; ■ Timeline for deployment; and ■ Major policy and regulatory hurdles.

If it was found that a particular source was not suitable as a top importing nation following an interview, it was replaced by another project source.

¹ IEA Energy Security, [<https://www.iea.org/topics/energy-security>]

Landed Cost Analysis

The landed cost of hydrogen in Singapore for each project (over the period of 2020 to 2050) was estimated as part of the assessment. The landed cost data has been collated through review of sources and direct engagement with the project developer and other potential stakeholders such as governments, associations and project financing organisations. The landed cost comprised a summation of the following six cost elements:

- Hydrogen production;
- Transformation to carriers;
- Carrier storage (at the load port);
- Transportation via a seaborne vessel or pipeline;
- Carrier storage (at the discharge port); and
- Hydrogen liberation.

- Hydrogen production;
- Transformation to carriers;
- Carrier storage (at the load port);
- Transportation via a seaborne vessel or pipeline;
- Carrier storage (at the discharge port); and
- Hydrogen liberation.

This study assessed more than 100 projects in phase one, and shortlisted of 12 potential hydrogen import sources for Singapore in phase two. All of these announced hydrogen projects are in the early or demonstration stages. A collaborative approach with exporting nations will likely be required for scaling and to secure future offtake agreements. A summary of the top 12 projects including source of energy, production technology, proposed hydrogen carrier, and project export commencement year is shown in Figure 6.1 below:

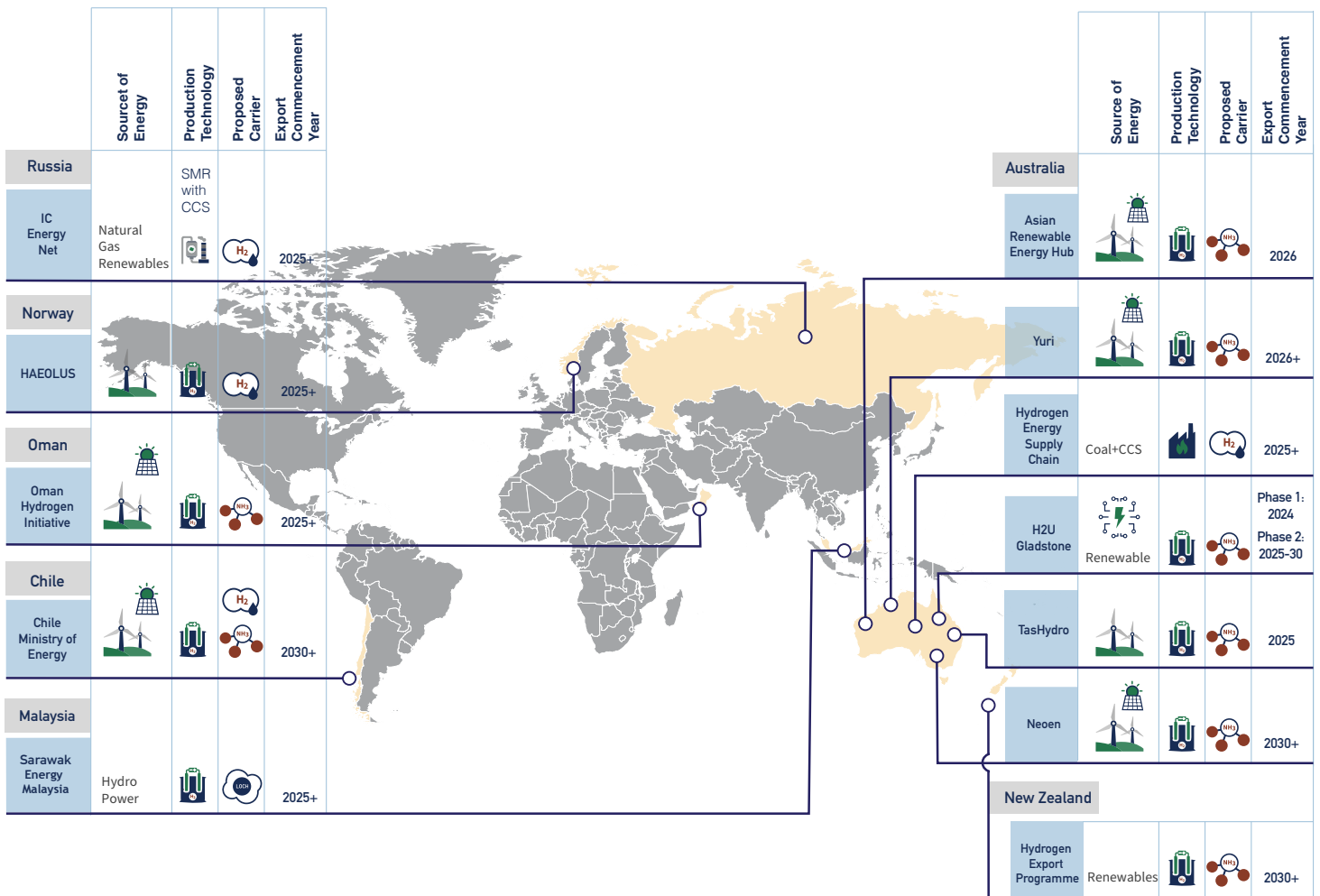


Figure 6.1 - Hydrogen Import Sources Analysis

From the analysis, import sources that were considered to have a higher likelihood of developing hydrogen

export projects were assessed for potential export volumes. These volumes are depicted in Figure 6.2.

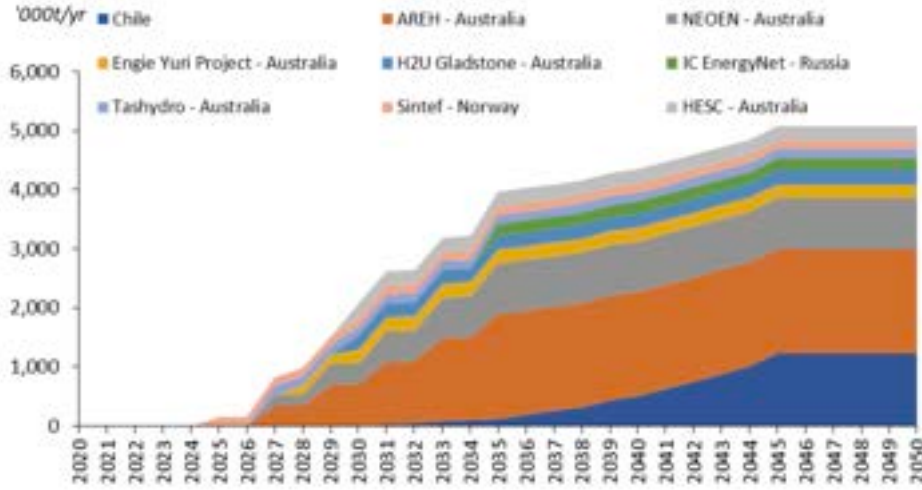


Figure 6.2 – Potential Hydrogen Supply from Import Projects that were Considered to have a Higher Likelihood of Producing Hydrogen for Export

The 12 potential hydrogen import sources and landed cost are given in Figure 6.3. Singapore landed costs are much higher compare to prevailing natural gas prices; however, the projects with more competitive prices (dropping below USD 4.00/kg by 2050) include Asia Renewable Energy Hub, Yuri, Oman and Sarawak Energy. Aside from importing hydrogen, there is an opportunity for Singapore to potentially meet some of its hydrogen demand through domestic hydrogen production.

The projected landed costs were based on interviews and assessment conducted in early 2020. Since then, numerous studies have continued to project steeper reductions in landed costs. Numerous countries have also put forward ambitious price targets, such as Australia's stretch goal of green hydrogen production cost under AUD 2/kg (around USD 1.55/kg) and Japan's target to reduce landed cost to 30 yen/Nm³ (around USD 3.3/kg).

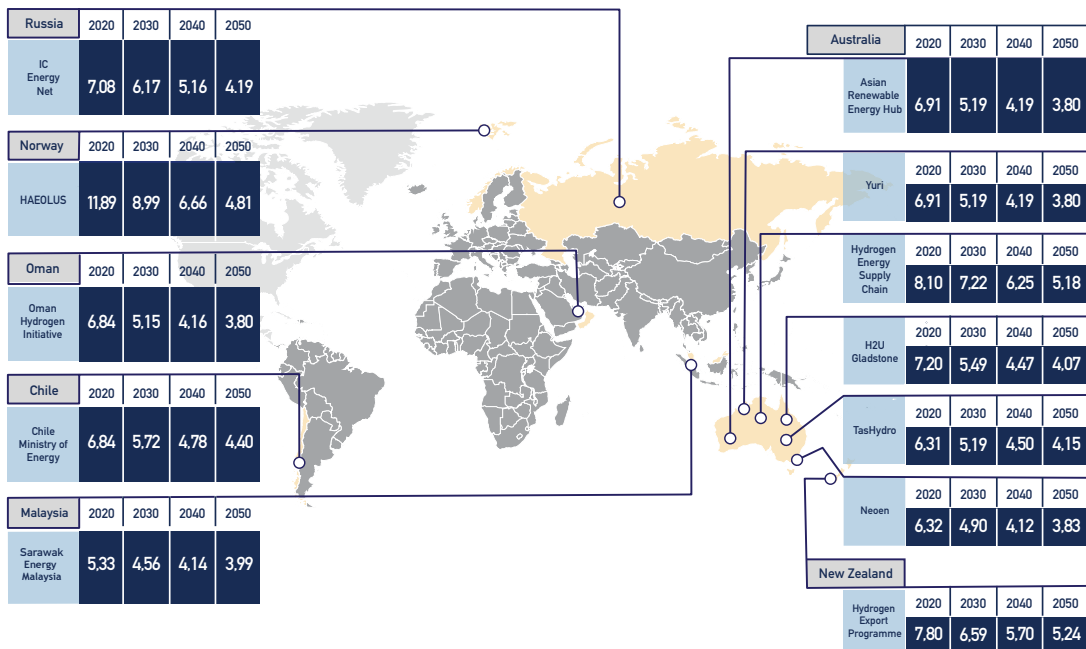


Figure 6.3 – Hydrogen Import Sources and Landed Costs in USD/kg of Hydrogen

[Note: Cost figures were based on assessment done in early 2020. Since then, newer projections of cost figures are lower in absolute terms.]

Domestic production methods and costs are shown in Figure 6.4 and are compared with the landed cost of imported hydrogen from Neoen project. As can be seen from Figure 6.4, the prices of producing blue hydrogen in Singapore are likely lower than the landed costs of

hydrogen until 2050, however it should be noted that the footprint requirements and land constraints within Singapore may limit the volume of hydrogen that can be produced domestically. Therefore Singapore may need to rely on imports to meet demand.

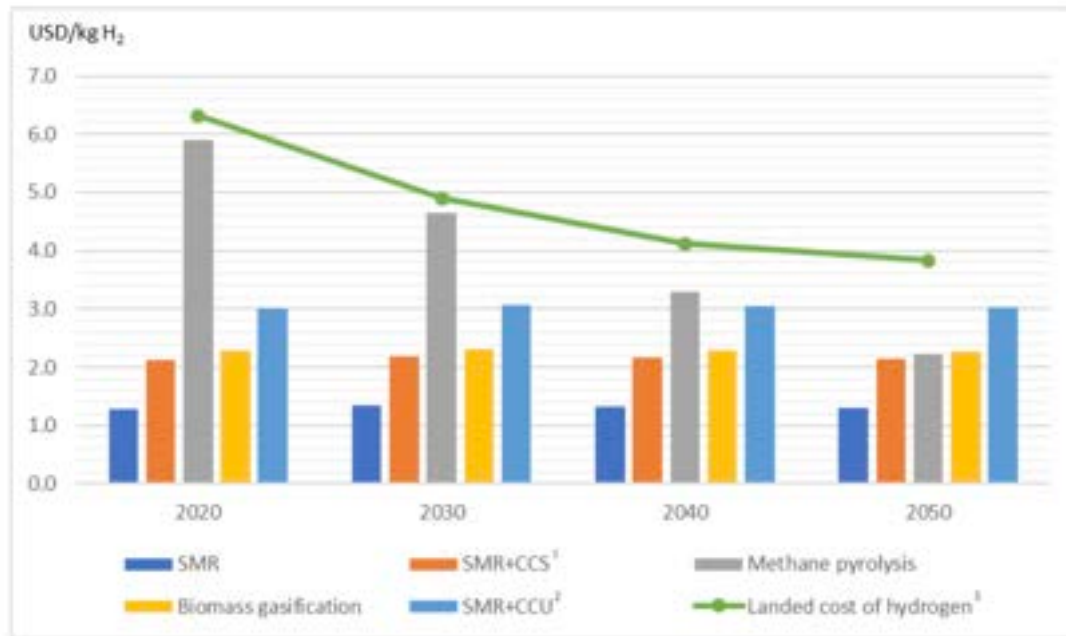


Figure 6.4 –Singapore Domestic Hydrogen Production Costs vs. Landed Price Hydrogen

Notes:

¹Based on USD 98/tonne CO₂ captured.

²USD 200/tonne CO₂. Assuming mineralisation as utilisation pathway. CO₂ to chemicals/fuels utilisation pathways will likely result in higher costs. Includes carbon capture cost, landfill cost avoidance and discount due to product revenue.

³Landed costs from Neoen project.



For each of the projects, a sensitivity analysis was undertaken to identify the areas of each supply chain which have the largest influence on the landed costs of hydrogen into Singapore, and also highlights the signposts which Singapore can identify for each project. The findings and signposts are as follows:

- For projects where hydrogen is produced from electrolysis, the largest influence on the landed cost is electricity price which influences the landed costs by ± 4-16% depending on the project. Signposts to look out for are regional changes in electricity prices and significant (> 15%) increases in electrolyser efficiency.
- For projects that produce hydrogen via SMR + CCS the largest influence on the landed cost of hydrogen is the natural gas feedstock price. Signposts to look out for with these projects are a reduction in natural gas prices.
- For projects which select liquefied hydrogen as a carrier, the liquefaction process is the largest influence of the landed cost of hydrogen. Improvements in hydrogen liquefaction efficiency and reduced CAPEX due to low-cost material development should be signposts for improved project economics.

Further analysis was undertaken to account for the uncertainty within the landed costs with a high and low comparative landed costs analysis conducted for each carrier. The results for each supply chain are shown in Figure 6.5 to Figure 6.7.

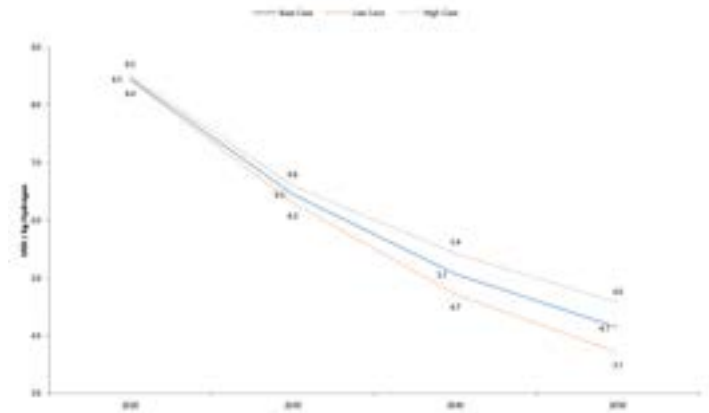


Figure 6.5 – Sensitivity Analysis for Low and High Case Hydrogen Landed Cost via Liquefied Hydrogen Supply Chain

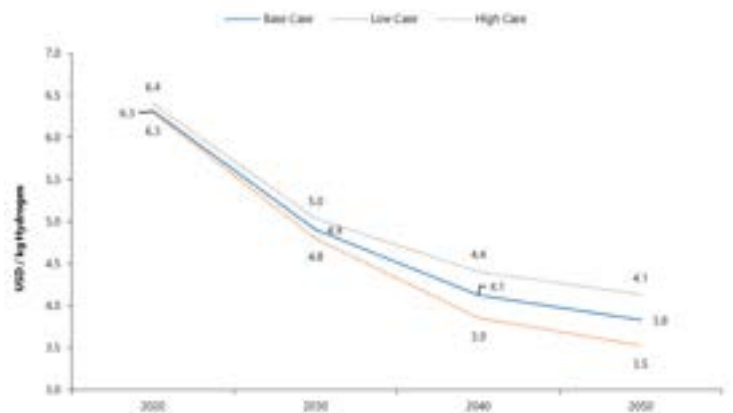


Figure 6.6 – Sensitivity Analysis for Low and High Case Hydrogen Landed Cost via Ammonia Supply Chain

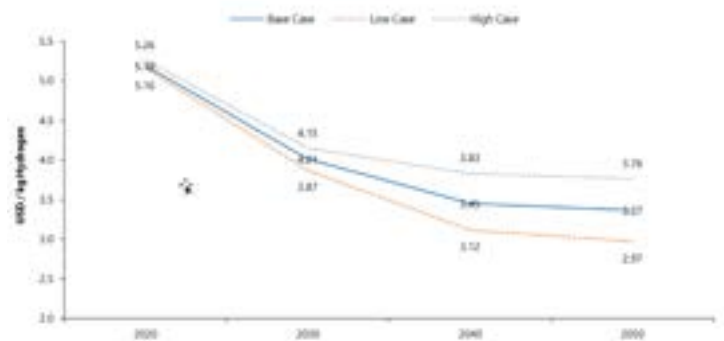


Figure 6.7 – Sensitivity Analysis for Low and High Case Hydrogen Landed Cost via LOHC (MCH) Supply Chain

Key Findings and Recommendations

Key findings derived from the hydrogen import sources assessment are:

- The landed prices for hydrogen imports into Singapore are much higher than current natural gas prices. However, there are several projects and locations where price is more competitive, dropping below USD 4/kg by 2050, which could be strategic target areas for Singapore. These include:
 - » Asian Renewable Energy Hub;
 - » Yuri;
 - » Neoen;
 - » Oman; and
 - » Sarawak Energy.
- Announced hydrogen projects are at early or demonstration stages.
- A few projects have stated that they cannot accurately predict their future export potential as they need engagement from importing nations prior to Final Investment Decision (FID) approval.
- Without guaranteed off-takers, and resulting investment risk, project developers may not be prepared to speculatively build hydrogen production facilities and the existing infrastructure associated with it.
- Project cost reduction is primarily driven by decreasing hydrogen production costs. In particular, the reduction in costs of hydrogen production feedstock, i.e. electricity or natural gas, has the largest weighting on the reduction of the landed costs.
- A collaborative approach with exporting nations may be required for scaling and to secure future off-take agreements.
- Nations committed to developing a hydrogen-based economy (such as Japan and Germany) have established strategic relationships with emerging hydrogen export nations built through collaboration at a RD&D, technical, commercial, and industrial levels.

If Singapore wishes to establish a hydrogen-based economy which involves large volumes of hydrogen imports, it is recommended that Singapore:

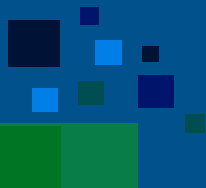
- Establish a collaborative approach with exporting nations or projects for scaling and to secure future off-take agreements.
- Engage on a one-to-one basis at a ministerial level with the respective exporting nations to ensure that a hydrogen export economy can be facilitated successfully.
- Consider early investments in hydrogen projects as this is more likely to assure off-takes and energy security.
- Engage on a techno-economic level with the individual project developers to ensure that funding, supply chain, off-take agreements and pricing can be agreed to enable the first hydrogen exports to Singapore.



07

Singapore Downstream Sectors Assessment

"A detailed techno and economic assessment was performed to determine the feasibility of transitioning Singapore's downstream sectors to hydrogen."



The various parts of Singapore's downstream sectors that were assessed for hydrogen adoption are shown in Figure 7.1 below.

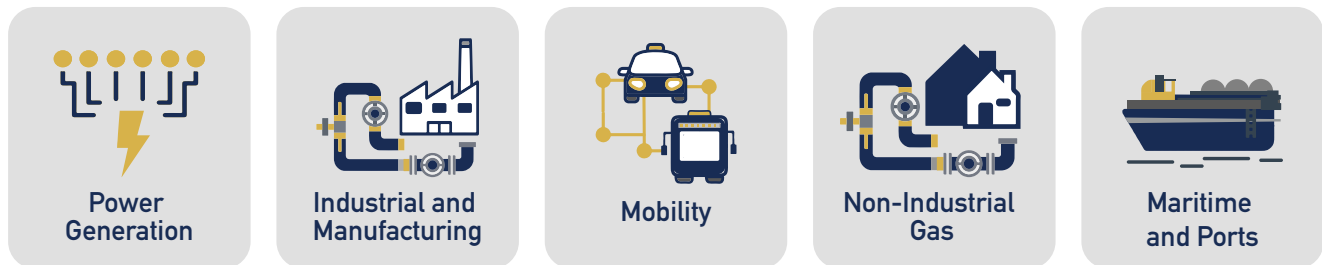


Figure 7.1 - Assessed Downstream Sectors

Section 13 provides an assessment of existing infrastructure within Singapore. This includes LNG facilities, the natural gas pipeline network, salt caverns and chemical storage. The assessment will determine if any of these assets can be repurposed for the carriers assessed in Section 5, namely liquefied hydrogen, ammonia, and LOHC.

The assessment for the downstream sectors includes:

- An overview of the landscape of each sector in Singapore currently, including key stakeholders, current operating models and constraints;
- A technical review of current hydrogen and other low-carbon technologies that could be deployed in the sector. This includes current nations and organisations who are leading RD&D efforts in these technologies, as well as reviewing any gaps and barriers that currently exist for deployment;
- An analysis of breakeven prices for hydrogen in each downstream sector;
- Potential deployment cases for hydrogen in each downstream sector, including the estimated hydrogen demand and CO₂ abated; and
- A technical and economic analysis of the infrastructure required for each sector and a +/- 50% CAPEX estimate for the infrastructure.

Conclusions and recommendations are used as the basis for the development of deployment pathways in Section 15.

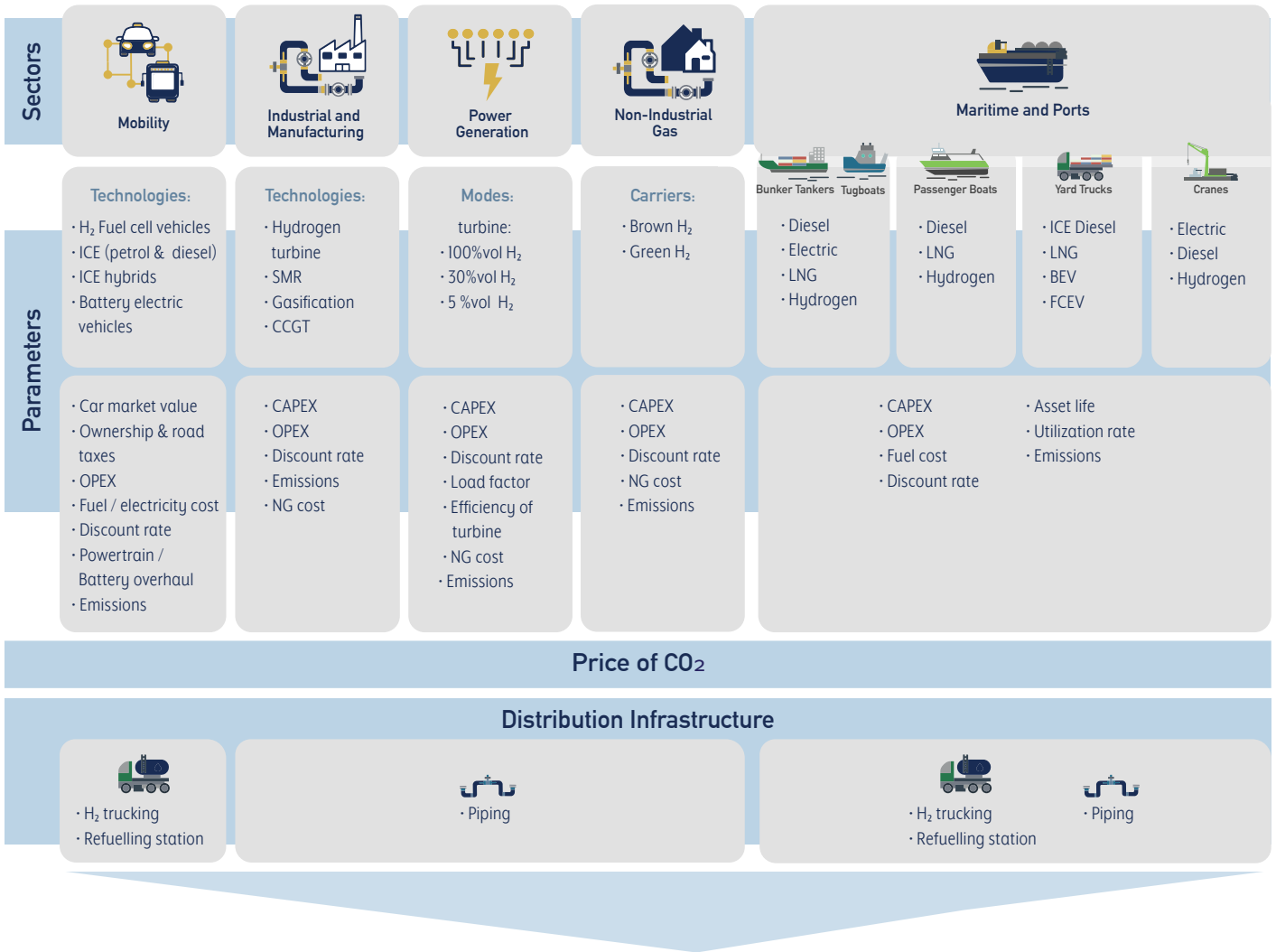
Breakeven Prices Methodology

To examine the techno-economic competitiveness of potential hydrogen consuming sectors in Singapore, breakeven models were developed wherein the total cost of ownership (TCO) of a technology that runs on hydrogen was compared against the alternative being considered. This would give us the levelised price of hydrogen at which the TCO was equal to the alternative source.

A bottom-up approach is followed. As such, capital costs, and operating costs, (including the fuel component, and taxes, which are significant in the mobility sector) are taken into consideration for each technology. Various technologies and parameters are captured as per in Figure 7.2.

The breakeven prices shown exclude consideration of carbon prices and the cost of abating emissions from the fossil fuel sector alternatives. These two factors will need to be included for any cost benefit analysis in order to present a complete comparison between technologies.





BREAKEVEN H₂ PRICES

Figure 7.2 - Overview of Breakeven Price Model



Breakeven prices for the downstream sectors are given in Figure 7.3 below. The breakeven prices shown exclude consideration of carbon prices and the cost of abating emissions from the fossil fuel sector alternatives. These two factors will need to be included for any cost benefit analysis in order to present a complete comparison between technologies.

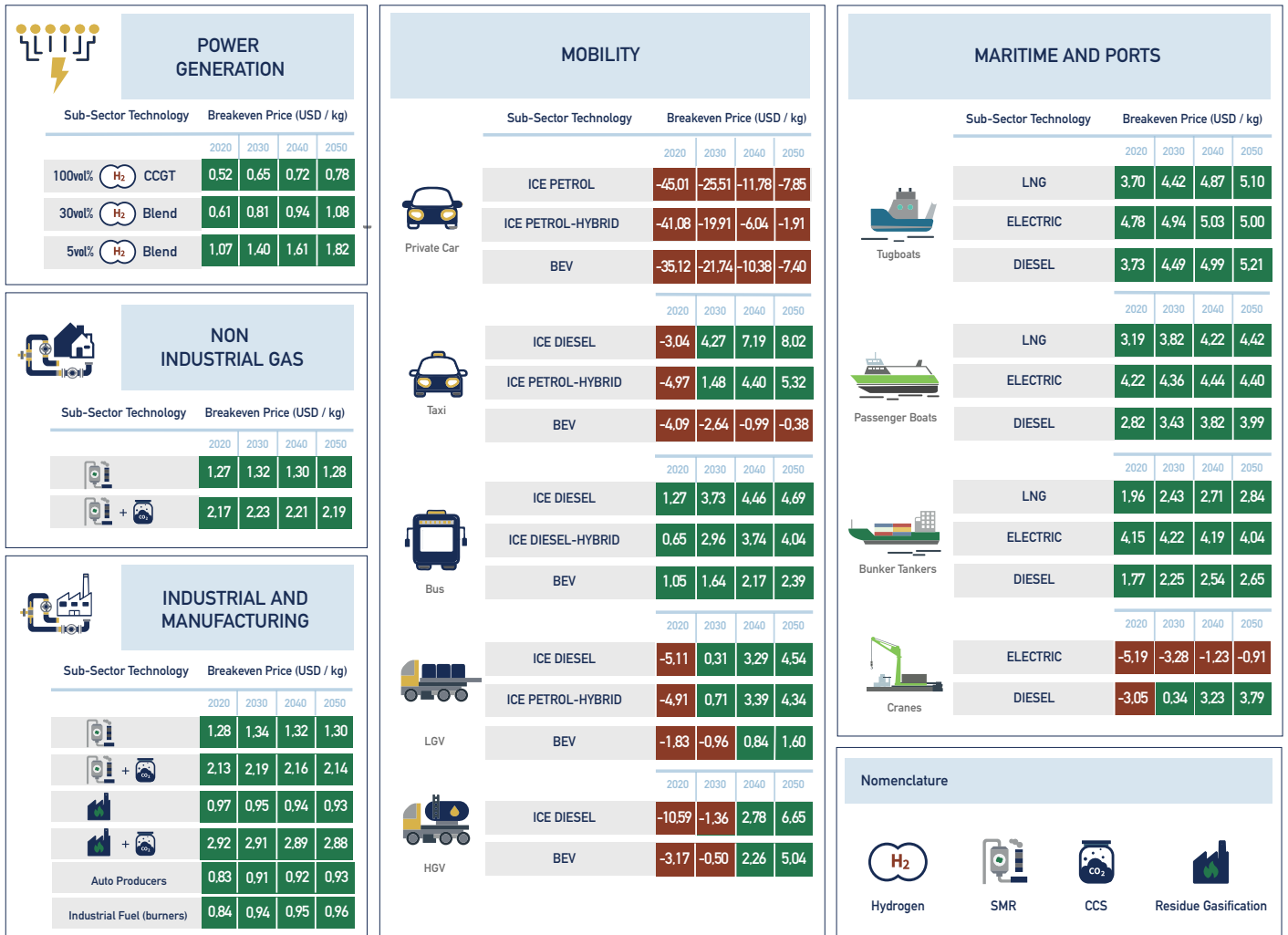


Figure 7.3 - Hydrogen Breakeven Prices



08

Non-Industrial Gas

"Introduction of low-carbon hydrogen into the non-industrial gas sector provides an opportunity to start hydrogen deployment in Singapore. This is possible since the infrastructure required for this transition is mostly available."



There are two main modes of non-industrial gas supply in Singapore:

- Piped town gas; and
- Liquefied Petroleum Gas (LPG).

Piped town gas is supplied to domestic (residential) and non-domestic (shops, restaurants, industrial etc) end-users. LPG is predominantly used for cooking with the main disadvantage being interrupted supply, less safety due to more frequent handling plus movement risk, as well as cylinders storage space requirements. An increasing proportion of the population and businesses have switched from LPG to piped gas since newer buildings are connected to town gas pipes. The convenience of an uninterrupted piped gas supply is the key driver for increasing switch to piped gas.

Singapore's Town Gas Production

City Gas Pte Ltd owns and operates Senoko Gasworks (SGW) located in the north of Singapore. It has a production capacity of 1.6 million m³ per day. Currently, town gas is produced by Steam Methane Reforming (SMR) from piped natural gas that is off-taken from the natural gas transmission network. SGW also receives naphtha from its jetty terminal.

Two types of syngas producing SMR plants are used to meet daily demand with peak periods of high gas demand. Both plants use either natural gas (85% of the time) or naphtha (15%) as feed stock¹. They currently produce an estimated 35 tonnes per day. Syngas is a mix of hydrogen, CO₂ and CO. The syngas is then enriched with natural gas and naphtha to make town gas. Enrichment blending is required to increase the energy value to town gas specifications while maintaining within range of Wobbe² index specification. The blending facility is on-site at Senoko. The current town gas distribution network can operate on natural gas but is not designed for hydrogen service, while various user appliances are not designed to run on natural gas or pure hydrogen.

CITY GAS IMPORTED HYDROGEN PILOT PROJECT

City Gas Pte Ltd is currently working with NRF and a consortium of partners including Chiyoda to explore the possibility of developing a supply chain with MCH, including, using imported hydrogen to produce town gas. As town gas does not require a high hydrogen purity, the hydrogen recovery process, via dehydrogenation of MCH, is applicable for town gas application. Currently, the cost to import and dehydrogenate NCH for in-situ blending at the Gasworks remains high. It will only become viable when the price of imported hydrogen drops further in the future.

This potential pilot project may be able to test the hydrogen import supply chain and also start the development of the infrastructure required to transition to green hydrogen. MCH technology is readily available, with Chiyoda using their existing Brunei facility to produce the hydrogen through SMR. Although MCH has been chosen for this pilot project, it is not an indication of the carrier preferred by the partners.

¹ Interview with City Gas Pty Ltd, 5th March 2020.

² The Wobbe index is used to compare the combustion energy output of different fuelling gases in appliances. If two fuels have identical Wobbe indices, then for given pressure and valve settings, the energy output will also be identical. The Wobbe index is a critical factor to minimise the impact of the changeover when analysing the use of different fuelling gases. It gives an indication of whether a turbine or burner will be able to run on an alternative fuel source without tuning or physical modifications.

Town Gas Decarbonisation

Town gas energy consumption is a small fraction of Singapore’s energy mix, around 2%, and as such a relatively small CO₂ emitter, around 1% of Singapore’s total emissions. Nevertheless, it could be an initiating sector for hydrogen deployment as:

- Hydrogen is already part of the infrastructure since piped town gas already contains 43vol% - 65vol% hydrogen; and
- Minimal disruption to the sector is expected by replacing the brown hydrogen volume in kind with low-carbon hydrogen.

The four options considered for potential hydrogen deployment in the sector are listed and detailed in Figure 8.1 below.

It was concluded through the assessment that carbon abatement and hydrogen demand for full replacement of the non-industrial gas infrastructure to process 100% hydrogen was not sufficient to justify the cost and disruption associated with this option. This will be discussed further in this section.

OPTION	OPTIONS TO REPLACE BROWN HYDROGEN	PRODUCTION PATHWAY	HYDROGEN DEMAND (ktpa)
ONE	43vol% blend of imported blue / green hydrogen	Hydrogen produced from renewable sources or from fossil-based production with CCUS blended with natural gas to achieve 43vol% composition	27
TWO	65vol% blend of imported blue / green hydrogen	Hydrogen produced from renewable sources or from fossil-based production with CCUS blended with natural gas to achieve 65vol% composition.	35
THREE	Carbon capture retrofitted to the SMR facility	Hydrogen produced from fossil-based production with CCS or CCU.	0
FOUR	100% imported blue/green hydrogen	Hydrogen produced from renewable sources or from fossil-based production with CCUS to replace the SMR and town gas composition.	77.8
RISKS	<ul style="list-style-type: none"> • Hydrogen supply will depend of the development of international blue or green hydrogen supply chain. • Increased cost compared to domestic production of hydrogen. • Hydrogen storage may be required for buffer increasing costs further. • To compensate the reduction of about 5% in the carrying capacity of town gas distribution network, augmentation of the network such as additional pipelines and larger pipe configuration would be required to ensure that it can still meet the required gas demand of end users. 		
	<ul style="list-style-type: none"> • Currently no clear path to utilise or store the carbon in Singapore. • High CAPEX which could increase the cost of gas to consumers. • Lowest carbon abatement of all options. 		
	<ul style="list-style-type: none"> • Most disruptive and expensive option with full change out of town gas distribution network or domestic appliances required. • Least inherently safe option due to additional safety risks of introduction of hydrogen into homes. 		

Figure 8.1 - Options Considered for Hydrogen Deployment in Town Gas

Marginal Abatement Cost (MAC)

The MAC has been calculated for options 1, 2 and 3 to determine the most economic pathways to abate CO₂ in the town gas sector. The MAC curves for the non-industrial gas sector are a net present value calculation of the costs and emissions of current SMR technology vis-à-vis the technologies for options 1, 2 and 3. Figure 8.2 details the MAC for the non-industrial gas sector.

ADVANTAGES

- Centralised receiving and distribution facility for the industry via pipeline.
- Zero carbon emissions in Singapore from the SGW SMR facility.
- No change to town gas distribution network or domestic appliances.

- Hydrogen production will remain local and integrated with the industry.
- No change to town gas distribution network or domestic appliances.

- Largest CO₂ abatement with zero carbon emissions for Singapore in entire town gas sector.

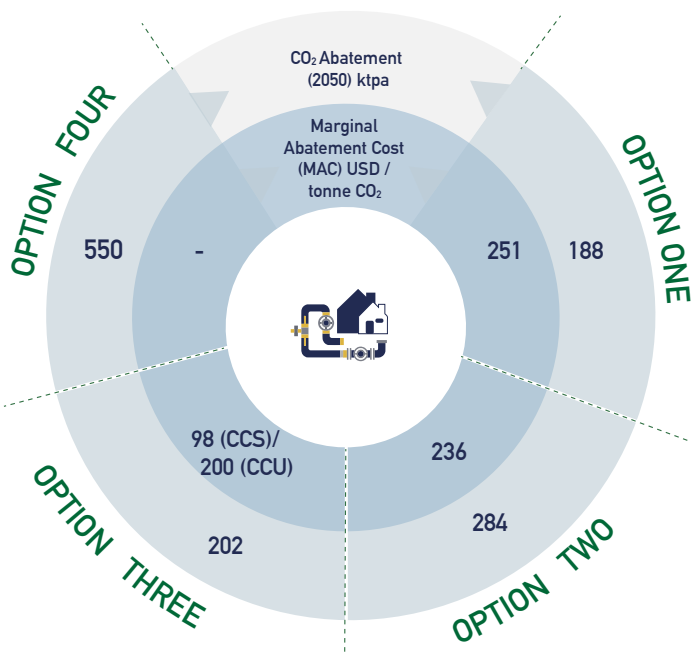


Figure 8.2 - Non-Industrial MAC

As shown in Figure 8.2, CCS provides the most economic MAC for the non-industrial gas sector, followed by CCU. By 2040, the MAC of the 43vol% and 65vol% blend is relatively comparable to the CCS and CCU options, with 65vol% being the most competitive of the two.

The marginal abatement cost was not calculated for Option 4 as it was deemed to be technically and economically unfeasible. The CAPEX and OPEX were the highest of the options making it the most complex, disruptive and expensive option.

Conclusions and Recommendations

Introduction of low-carbon hydrogen into the non-industrial gas sector provides an opportunity to start hydrogen deployment in Singapore since the infrastructure required for the transition is mostly available. A pilot trial is being explored to test the hydrogen import supply chain and the blending of imported hydrogen into natural gas for domestic gas uses.

Of the four options considered, options 1, 2 and 3 are shortlisted for the formulation of deployment pathways.

Options 1 and 2 provide the least disruptive options to reduce carbon emissions and introduce hydrogen into the town gas sector. These two options would require a modest amount of additional infrastructure requirements at SGW to avoid disruption to downstream town gas users and changes to safety risk profile.

Option 2 provides a slightly more competitive MAC of the two, and becomes competitive with the CCU and CCS options around the year 2040. Despite this, option 2 would result in an associated decrease in the carrying capacity of the town gas distribution network by around 5%. To compensate for this reduction, augmentation of the network such as additional pipelines and larger pipe configurations, would be required to ensure that supply can continue meeting required gas demand of end-users.

Option 3 provides 93% abatement as well as the lowest MAC. This option carries significant risk with regards to the utilisation and / or storage of carbon. There should be a clear utilisation or CO₂ storage pathway in Singapore or neighbouring countries to deploy this option. There is no step change in safety or security risks associated with this option.

For option 4, the CAPEX and OPEX were the highest of the options making it the most complex, disruptive and expensive. As the carbon abatement for this sector is only 1% of Singapore's total abatement, this option should not be recommended for deployment within Singapore.



Further, the results of the assessment showed that several of the principal considerations were not met for option 4:

- The increased safety risk of gas leak and explosion pertaining to piping 100% hydrogen through buried pipelines across urban areas of Singapore and into residential homes;
- The technical and commercial complexity and feasibility of replacing the current piping infrastructure and the conversion of household appliances to accept 100% hydrogen; and
- The level of disruption caused to Singaporeans through the replacement of the current piping infrastructure and the conversion of household appliances.

» The breakeven price of hydrogen remains challenging for this sector throughout the forecast period. Introducing a carbon tax of USD 270/tonne could result in additional costs passed onto town gas consumers. Since the breakeven price is unfavourable throughout the forecast period, it is unlikely that incentives could be used to defray costs. Generally, incentives are short-term stimulators and are used to accelerate deployment in parallel with the economics becoming favourable for that technology. A long-term natural gas price of USD 15/MMBtu would allow economic hydrogen deployment into the town gas sector. As such, an increase in natural gas prices could be a signpost for deployment in the sector. Furthermore, a reduction in the landed cost of hydrogen throughout the forecast period could also be a signpost. «



09

Power Generation

"Decarbonising this sector has the possibility of capitalising on Singapore's existing natural gas infrastructure as well as Singapore's mature and extensive electricity grid infrastructure. However, breakeven prices remain challenging throughout the outlook period"



Singapore currently has seven main power generation companies (gencos) that primarily use heavy duty combined cycle gas turbines (CCGTs) to produce electricity. Natural gas is provided to the gencos via the natural gas transmission network which is fed from piped natural gas from Malaysia and Indonesia, as well as from LNG imports.

95% of Singapore's electricity is currently generated through burning natural gas in CCGTs. The power generation sector is one of the Singapore's largest CO₂ emission contributors, responsible for 39% of carbon emissions in 2017¹. Therefore, power generation sector decarbonisation has the potential to contribute significantly to CO₂ abatement. Due to Singapore's mature and expansive electricity grid, this will have a knock-on effect on other sectors which draw from the electricity grid, thus potentially decarbonising many sectors simultaneously. Moreover, if hydrogen is used as a decarbonisation pathway for this sector, there is potential to generate large demand for low-carbon hydrogen. However, because of the commercial and operational structure of Singapore's power generation sector and relatively low natural gas prices, this sector is one of the most challenging to transition from a commercial standpoint. The following options to reduce carbon emissions via the use of hydrogen in power generation have been assessed in this report:

- Hydrogen blending;
- Hydrogen CCGTs;
- Carbon capture (storage or utilisation); and
- Fuel cells.

Gas Turbines for Power Generation

Hydrogen Enriched Natural Gas Turbines

Hydrogen enriched natural gas (HENG) turbines are CCGTs which run on a feedstock composition of natural gas and hydrogen. Blending hydrogen into natural gas feedstock has carbon abatement potential based on displacement of natural gas, as shown in Figure 9.1. Use of hydrogen in gas turbines is established in the industrial and manufacturing sector. For example, using hydrogen-rich fuel gas for power generation in refineries globally.

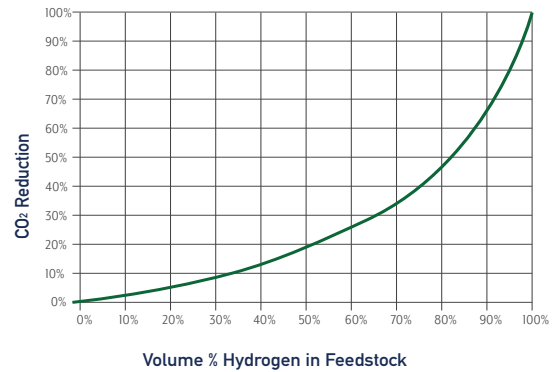


Figure 9.1: HENG Carbon Abatement Potential

Deploying hydrogen as a blend in Singapore's power generation infrastructure has the following potential implications:

- **Energy security:** the decrease in combustion stability for a hydrogen blend could result in increased risk of forced outages for HENG power plants. This may also be a concern for hydrogen CCGTs.
- **Safety:** Hydrogen in fuel blends could lead to possible leaks, and ignition. Any leaks could also result in shutdowns and possible damage. This may also be a concern for hydrogen CCGTs.
- **Hot switching and liquid fuels limitations:** Hydrogen blend liquid fuels such as fuel-oil or diesel may be used for hot switching. For blends over 30vol%, natural gas may have to be used for hot switching since it is uncertain whether liquid fuels can be used due to nozzle modifications. There is no impact on the gas turbine's ability to provide frequency regulation to maintain electrical grid stability when operating on blends of natural gas and hydrogen based on the limits stated. This may also be a concern for hydrogen CCGTs.
- **Footprint requirements:** Since hydrogen is volumetrically three times less dense than natural gas, there may be increased land take requirements of up to 5% depending on the blend of hydrogen within the fuel. This may also be a concern for hydrogen CCGTs.
- **Brownfield modifications:** Upstream of the combustion system for hydrogen blends, modifications may be required for component material and pipe sizes, as well as sensors and safety systems. Downstream of the CCGT, the exhaust path including the heat recovery steam generator

¹ Singapore's Long-Term Low-Emissions Development Strategy, [<https://www.nccs.gov.sg/docs/default-source/publications/nccsleds.pdf>]

must be evaluated and may require modifications. Varying exhaust gas properties can impact heat transfer and corrosion rates, possibly impacting the lifetime of components.

A retrofit can usually be implemented during a Hot Gas Path Inspection (HGPI) or a Major Outage. Depending on the gas turbine, the version of the gas turbine and the targeted amount of hydrogen, another retrofit during an extended minor outage retrofit might be possible. The exact scope and duration is project specific.

100% Hydrogen CCGTs

Hydrogen differs from hydrocarbon fuels by its combustion characteristics, which pose unique challenges for gas turbine combustion systems designed primarily for natural gas fuels. The main differences between methane and hydrogen combustion are:

- Flame temperatures for hydrogen under adiabatic conditions are almost 300°C higher than for methane.
- Hydrogen's laminar flame speed is more than three times that of methane, while the autoignition delay time of hydrogen is more than three times lower than methane.
- Hydrogen is a highly reactive fuel, making it challenging to control flame levels needed to maintain the integrity of the combustion system and reach the desired level of emissions².

Hydrogen turbines will be designed to meet all the usual GT operational requirements, including hot switching without a drop in load, providing frequency regulation and black start. However, these capabilities are still under development.

Ammonia Turbines

Ammonia can also be burnt directly in gas-turbines in a natural gas or hydrogen mixture. If ammonia is imported as a hydrogen carrier, burning it directly could eliminate the requirement for ammonia cracking, thus removing an energy intensive stage of the process. Ammonia gas turbines have a TRL of 4, significantly behind the development of hydrogen turbines. Furthermore, there is limited research concerning this technology.

Key challenges around direct firing of ammonia are:

- The increase in NO_x emissions;
- Lower flame temperatures and slower kinetics³;
- Stable, efficient combustion with liquid ammonia is problematic, thus additives should be used³;
- Ammonia can be burned in combustors in the vapour phase, thus there is a need to develop systems capable of vaporising ammonia³.

Ammonia requires 1.5 times less storage volumes and is less reactive than hydrogen. It burns at a lower temperature with reduced flame speed and has a narrow flammability range. The disadvantages of direct ammonia firing are that ammonia is a toxic gas and requires greater care to prevent and control environmental releases. While ammonia has a gas density comparable to that of natural gas, its lower heating value (LHV) is less than half that of natural gas. Consequently, it is also likely that fuel delivery systems and steam turbines will need to be replaced for ammonia. There is currently not enough interest in the development of ammonia turbines for it to be considered as an option for deployment in Singapore.

Power Generation Hydrogen Deployment Scenarios

From the assessment of the four options to reduce carbon emissions in this sector, it is concluded that fuel cells are not recommended as a technology for centralised, large-scale power generation. The major challenges with fuel cells for centralised power generation is that based on current fuel cell technology, the footprint required to meet the same generation capacity is over three times that for CCGT power generation. In addition, fuel cells are unlikely to be cost competitive with gas turbines for centralised power generation due to their high CAPEX. However fuel cells could play a role in Singapore's power sector for distributed power generation in data centres, particularly those which are single occupancy and for hospital back-up usage. This is discussed further in Appendix.

² Siemens, White Paper: Hydrogen Power with Siemens Gas Turbines, April 2020

³ Applied Energy, 2017, Ammonia-methane combustion in tangential swirl burners for gas turbine power generation

The main benefits and risks for power generation scenarios assessed is detailed in Table 9.1.

Table 9.1 – Power Generation Scenarios Benefits and Risks

Case	Benefits	Risks
5vol% Hydrogen HENG	<ul style="list-style-type: none"> ■ Maximising use of existing infrastructure. ■ Minimal disruption to sector. ■ Minimal increase in LCOE. ■ Early adopter of hydrogen. 	<ul style="list-style-type: none"> ■ Viability of all off-takers on NG network to accept 5vol% blend to be confirmed. If not technically viable this could be a showstopper.
30vol% Hydrogen HENG	<ul style="list-style-type: none"> ■ No impact to other gas network off-takers as dedicated pipeline to gencos required. ■ Optionality for gencos to opt in and out of using hydrogen based on commercial/ strategic decisions. 	<ul style="list-style-type: none"> ■ New gas network infrastructure required. ■ On-site blending for each genco. ■ Retrofit requirements for GTs.
100% Hydrogen CCGT	<ul style="list-style-type: none"> ■ No impact to other gas network off-takers as dedicated pipeline to gencos required. ■ Optionality for gencos to opt in and out of using hydrogen based on commercial/strategic decisions. ■ Largest potential carbon abatement of power generation sector. ■ Large hydrogen demand. 	<ul style="list-style-type: none"> ■ New gas network infrastructure required. ■ High LCOE and increased cost to consumers. ■ May unfairly penalise gencos which transition first. ■ Potential uncertainty in 100% H₂ CCGT technology commercialisation timeline.
CCGT + CCU / CCS	<ul style="list-style-type: none"> ■ Largest potential carbon abatement of power generation sector. ■ Large hydrogen demand. 	<ul style="list-style-type: none"> ■ Requirement for carbon utilisation or storage for deployment, which is dependent on technology maturity and G2G/G2B/B2B agreements respectively. ■ Increased LCOE of USD 60/MWh for CCU and LCOE USD 30/MWh for CCS. ■ Land footprint requirement of conventional amine post-combustion CO₂ capture technology is large and there may not be enough space to retrofit existing power plants with these units.

An economic summary of the breakeven price, LCOE (base case) and MAC for each option for 2050 is shown in Figure 9.2. For comparison the BAU LCOE for conventional CCGTs using natural gas in 2050 is projected to be USD 73/MWh.

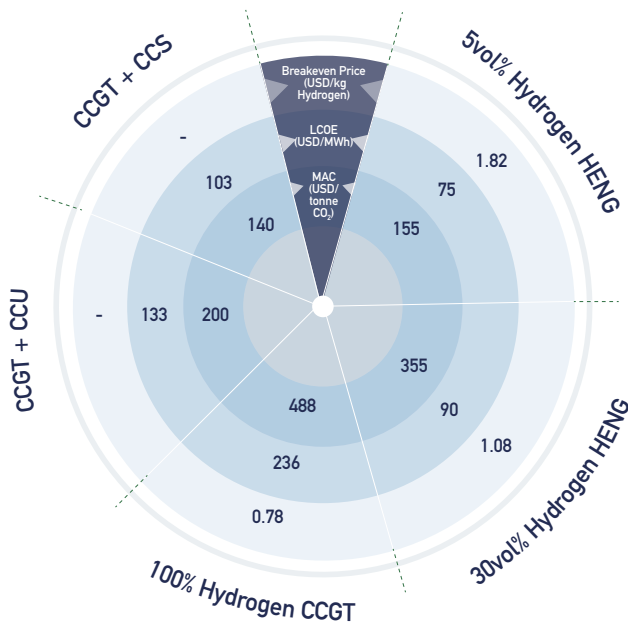


Figure 9.2 – Economic Summary of the Power Generation Scenarios 2050^{4,5}

A 5vol% hydrogen blend into the existing gas network offers the lowest CAPEX and infrastructure and footprint requirements of the various options available. A 5vol% hydrogen blend also has a minimal impact on the LCOE, with a USD 2/MWh increase from the base case CCGT, furthermore the MAC becomes more competitive with CCS by 2050. However, the carbon abatement potential of this option is 1% of Singapore's total abatement. The breakeven price of hydrogen is challenging at around USD 1.82/kg of hydrogen and an approximate landed price of USD 3.88/kg by 2050. Despite this, introducing a 5vol% hydrogen blend into the power generation sector in the forecast period could offer benefits, including:

- Early CO₂ abatement in industrial and power generation sector;
- Introduction of hydrogen into the sector for increasing knowledge of safety, handling, O&M issues, operator training and familiarisation;
- Establishing relationships with hydrogen export nations for future scaling;
- Demonstrating Singapore's commitment to meet its 2030 CO₂ abatement goals;

- Developing an infrastructure (hydrogen receiving and transmission) and know-how for additional hydrogen deployment in other sectors; and
- Increasing confidence in the APAC region towards the creation of a hydrogen supply chain.

The natural gas distribution network can handle higher hydrogen blend volume from a hydraulics perspective, albeit with a reduction in capacity. Other industrial and manufacturing end-users of the same network may not be able to accept this high blend volume therefore dedicated hydrogen pipelines and infrastructure will be required to provide hydrogen to the gencos. 30vol% blend option has the second-highest carbon abatement cost and the highest risk of stranded infrastructure in the long term. It also introduces a higher risk to the gencos as the brownfield modifications to the power plants could result in significant downtime if complications and unplanned issues arise.

However, it also provides options for gencos to change to a greener fuel. Additionally, it eliminates risks associated with blending into natural gas pipelines. By allowing gencos various change options, different policy levers can be introduced to defray costs such as a tiered electricity market and incentives for switching. Regardless, the 30vol% option is the least cost-effective way to introduce hydrogen into the Singaporean power generation sector, and as such should not be a consideration for deployment pathways.

For the 100% hydrogen option, a dedicated hydrogen pipeline and replacement of all the GTs will be required. 100% hydrogen turbine technology could be commercially ready for deployment by 2030, while turbine replacement could take place from 2030 onwards. As the hydrogen driven CCGTs are being designed to accept natural gas as well as hydrogen, transition could begin before hydrogen receiving infrastructure is ready.

The 100% option presents the most challenging economics. However, this option will allow for deep decarbonisation of Singapore's power generation sector and support it in achieving LED targets⁵. The MAC shows that a carbon tax of USD 488/tonne CO₂ in 2050 could be applied to defray costs and allow 100% hydrogen CCGTs to be competitive with conventional natural gas CCGTs. However, this may have knock-on LCOE effects for consumers. In the absence of a carbon tax, the LCOE is estimated to increase from USD 73/MWh for a conventional natural gas CCGT to USD 236/MWh for a 100% hydrogen CCGT.

⁴ CCS subject to availability of transboundary storage sites

⁵ CCU refers specifically to CO₂ mineralisation and other CCU pathways that are not included in the analysis, such as synthetic Kerosene or synthetic methanol, will likely be more costly compared to CO₂ mineralisation

Furthermore, as the landed cost of hydrogen and the breakeven price never equalise across the forecast period, it is unlikely that grants or subsidies will be suitable long-term solutions for enabling the transition. However, as the transition will likely be phased, incentive mechanisms could be put in place to ensure that genscos transitioning earlier are not unfairly penalised, for example:

- Cover the difference in CAPEX between a 100vol% hydrogen CCGT and a conventional natural gas CCGT; and/or
- Cover the difference in fuel costs between hydrogen and natural gas.



10

Mobility

"Over the years, Singapore has consistently sought to balance private vehicle ownership with the expansion of its public transport network taking into consideration road congestion, air quality, and carbon emissions. It is expected that in the near term, BEVs will most likely continue to have the edge over FCEVs in most vehicle sectors."



Singapore Land Mobility Sector Background

As Singapore's population and economy continue to grow, the demand for both private and public modes of transportation will likely rise in tandem. Since land is scarce in Singapore, careful planning will be required to manage this growth. This is especially important for private transportation, where an uncontrolled growth in vehicle population would result in more in-city congestion and an increased need to expand road networks and car parks, which is a less productive use of land.

Singapore has been mindful of these considerations when designing policies for road transportation, in particular for the private car population. It has, over the years, consistently sought to balance private vehicle ownership with the expansion of its public transport network taking into consideration road congestion, air quality, and carbon emissions. Singapore has recently embarked on a national car-lite effort by expanding public transport and an island wide cycling network, as well as further capping vehicle growth rates. These moves would influence Singapore's private vehicle landscape, and as such the corresponding decarbonisation strategy for the mobility sector.

Policies to Support and Enable the Transition towards Clean Vehicles

Singapore's transition towards cleaner energy vehicles is already underway for both private and public modes of transport. In its 2020 budget, Singapore announced a vision to phase out internal combustion engine (ICE) vehicles within the next 20 years. Additionally, it plans to have all vehicles use cleaner energy by 2040. The policy to enable this vision includes changes to the tax structure to incentivise/disincentivise adoption of cleaner and polluting vehicles respectively; and the expansion of EV charging infrastructure.

Singapore is in a unique position since it has the ability to continually refresh its vehicle fleet. In terms of vehicle ownership, Singapore has a policy where all vehicles require a Certificate of Entitlement (COE) which gives the holder the right to own and use the vehicle for a ten-year period. Through this mechanism, Singapore can completely refresh its vehicle fleet within a relatively short time period.

In a similar manner, Singapore has adopted a Bus Contracting Model (BCM) for its public bus transportation system, which has been in place since September 2016. The BCM brings all public buses and related infrastructure, such as integrated transport hubs, under government ownership. Public transport operators bid for the right to operate services along bus routes using government-owned buses and infrastructure. This allows the government to retain greater control in the planning and procurement of cleaner energy buses.

Clean Vehicle Adoption in Singapore

Of the 53,191 cleaner energy vehicles (i.e. hybrids, CNG, battery electric vehicles [BEVs]) deployed in Singapore as of 2020, most are hybrids (96%) and BEVs (3%). There are no FCEVs registered in Singapore as of 2020. In the near-term, hybrids are the clear leader for vehicle adoption. However, as battery prices fall and as more EV charging infrastructure is developed, the cost and usability of BEVs will improve. This could swing the market toward such zero-emission vehicles.

Given the positive outlook for BEV technologies and the policy support in place, it is expected that in the near term, BEVs will most likely continue to have the edge over FCEVs in most vehicle sectors. There might, however, emerge some niche applications for FCEVs (for example, heavy goods vehicles [HGVs]) where FCEVs could have an advantage over BEVs due to operational requirements.

Over the long-term, technical progress will determine if the two clean transportation modes will be more evenly matched, especially cost levels. Significant breakthroughs in fuel cell technology that drive costs down significantly will have to materialize in order for FCEVs to compete with BEVs.

FCEV Systems

An FCEV is an electric vehicle that uses a fuel cell, sometimes in combination with a small battery or super capacitor to power its onboard electric motor(s). Mechanically, FCEVs are identical to BEVs with hydrogen containment usage being the primary exception (to store the compressed gaseous hydrogen¹ and fuel cell stack(s) in place of a battery). The electric motor used to propel two or more wheels in both an FCEV and BEV are similar, resulting in both vehicles having similar performance and high efficiency as compared to an ICE vehicle.

¹ Wikipedia, Fuel Cell Vehicle, [https://en.wikipedia.org/wiki/Fuel_cell_vehicle#:~:text=A%20fuel%20cell%20vehicle%20\(FCV,the%20air%20and%20compressed%20hydrogen.](https://en.wikipedia.org/wiki/Fuel_cell_vehicle#:~:text=A%20fuel%20cell%20vehicle%20(FCV,the%20air%20and%20compressed%20hydrogen.)

FCEV Refilling

The FCEV refilling process is similar to that of ICE vehicles where drivers travel to refilling points at controlled locations (similar to petrol refilling) and refill through Hydrogen dispensers. Hydrogen dispensers are built with various features, including breakaway hoses, leak detection sensors, and grounding mechanisms to ensure safe refilling. Given the lower density of Hydrogen, FCEVs require a slightly longer refilling time (around three minutes) compared to an equivalent ICE (about 1.2 minutes). Despite this, refilling time for FCEVs is significantly shorter than the time required to recharge a BEV. For their part, BEVs can require as much as 45 minutes to charge using fast chargers, and four hours using home slow chargers. While improvements are expected in BEV recharging times through improvements in battery cooling technologies and wider deployment of faster chargers, BEV recharging times are likely to remain high compared to FCEV refilling times. For fleet vehicles such as taxis, buses and goods vehicles, high BEV charging times creates operating model challenges and the potential need for larger fleets.

Hydrogen Filling Stations

A Hydrogen filling station looks and operates similarly to a petrol filling station. However, FCEV filling points must be in controlled locations because of containment loss, fire and explosion risks. Compared to petrol stations, such risks are generally higher for Hydrogen than for ICE fuels. This higher risk profile means that there may be current ICE refuelling stations that are not appropriately located for possible FCEV refilling stations.

Two key systems for Hydrogen filling stations, include a Hydrogen dispenser and Hydrogen storage system. Hydrogen filling stations (HFS) store hydrogen in either gaseous (compressed, GH₂) or liquid (LH₂) form. GH₂ is stored in high-pressure vessels or cylinders ('tubes') at typically 400 to 800 barg. LH₂ is stored cryogenically at -253°C in large vessels, which can be located above- or below-ground along with the cryogenic system required to maintain the hydrogen in liquid form. The choice between LH₂ and GH₂ will not affect driver refilling experiences however, it will determine the design and size of hydrogen storage and delivery facilities.

Hydrogen dispensers function the same as existing gasoline dispensers, with complete sealing of vehicle hydrogen containment tanks and various sensors and controls to help to ensure safety. FCEV drivers can refill their own vehicles. As mentioned earlier, FCEV filling

points must be in controlled locations because of higher containment loss, fire and explosion risk than for ICE fuels. This means that there may be ICE refuelling stations that are not appropriately located for FCEV refilling stations.

An HFS will look and operate in much the same way as existing gasoline service stations. The fundamental differences can be summarised as follows:

1. Wider spacing between dispensers for safety reasons (currently defined by QRA), leading to larger forecourts or, more likely in Singapore's case, fewer dispensers per forecourt;
2. Above-ground hydrogen storage and delivery facilities (this is currently the industry norm however, some HFS designers and vendors offer a below-ground design).
3. Modified forecourt awnings to ensure that there are no pockets where escaping hydrogen can accumulate;
4. In case of trailer delivery, more frequent LH₂ or GH₂ trailer deliveries to compensate for the lower transported density of hydrogen and the reduced payload of volume per trailer (particularly for GH₂);
5. Permanent mobile storage areas for liquid hydrogen (LH₂) or green hydrogen (GH₂) trailers to supplement fixed on-site storage. This is due to the higher frequency of deliveries and the ease of logistics. When the prime mover makes a delivery, it will unhook from full delivery and attach directly onto the empty load; and
6. In the case of pipeline delivery, the absence of delivery trucks entirely and the space and facilities required to accommodate them.

HFSs are scalable up to around 2,000 kg/day² and can be designed to meet requirements for the types of vehicles using the facility, and the usability demand³. Retrofitting hydrogen refilling infrastructure into existing stations is also feasible, subject to available space. This would involve installation of hydrogen storage, delivery and dispenser systems along with some civil redesign in order to meet safety requirements, and possible removal of existing fuel tanks and delivery systems.

The average footprint for a service station in Singapore is approximately 2,000m²⁴, therefore total land area for the 186 existing public service stations is estimated at 380,000m². These existing service stations deliver approximately 4 million L/day of petrol and diesel to consumer vehicles. Equivalent hydrogen demand assuming complete transition to FCEV would equal 638,000 kg/day. Assuming a footprint of 2,000m² for

² Sgcarmart.com, Petrol Stations, [https://www.sgcarmart.com/news/carpark_index.php?LOC=all&TYP=petrol]

³ Private correspondence with a hydrogen supplier, [External] RK857 - Hydrogen Refilling Station Economics, 02/01/2020.

⁴ HDB, Petrol Stations Sold by HDB, [https://www.hdb.gov.sg/cs/infoweb/doc/petrol-station-(ps)].

an 800 kg/day HFS⁴, then the total land area required increase to 1,600,000m². Larger HFSs in the order of 2,000 kg/day will have a smaller footprint per kg/day of output; however, the conversion of existing service station sites to HFSs and the absence of available surrounding space may limit the size of HFSs to 800 kg/day unless separation distance and/or transaction time can be reduced.

Hydrogen Fuel Distribution

Hydrogen can be either distributed from a central terminal to HFS via truck (as with the current fossil fuel distribution model) or via pipeline. Transporting bulk hydrogen introduces challenges that apply to both methods, in particular larger volumes and higher leak propensity. Hydrogen is the smallest known chemical molecule and is often handled at high pressures when in gaseous form, which makes it more difficult to contain, while traditional materials, such as steel, are more susceptible to hydrogen cracking.

The assumed mobility hydrogen distribution model for the deployment pathways is using trucked LH₂. Shifting to GH₂ distribution by tube trailer increases the investment required by 6% and to GH₂ pipeline distribution by 28%.

Under the deployment scenarios, a complete transition to FCEV in Singapore will require 40 truck deliveries per hour compared to the current 18 truck deliveries per hour to distribute conventional fossil fuel.

FCEV Cost Trends

Vehicle Cost Trends

FCEVs and BEVs compete in the same space since they offer zero tail-pipe emissions and have the opportunity to decarbonise the road transportation sector. One key advantage that FCEVs have over BEVs is that their range and refuelling characteristics are similar to ICE vehicles. However, compared with BEVs, FCEVs are substantially more expensive. While price isn't the only criteria that buyers would use to evaluate a vehicle purchase, it does contribute significantly to the purchasing decision of the average car buyer. It is in this regard that FCEVs have lagged behind their BEV counterparts.

Despite large reductions in fuel cell costs, upfront costs of an FCEV remain high (see Figure 10.1) which is to some extent a function of the small production volumes⁵. As of 2018, the cost of fuel cells, which contribute to around 40% of the cost of a FCEV passenger car, was USD 200/kW.

Economies of scale along with research-driven advances in technology and optimisation of fuel cell system design are expected to reduce costs to around USD 50/kW by 2035⁶.

Hydrogen storage tanks represent another significant contributor to the high cost of FCEVs and is consequently responsible for around 15% of the market price of a FCEV passenger car as of 2018. Tanks are made from composite materials that are relatively technologically mature and hence their prices are expected to fall at a slower pace than fuel cells. Storage tanks costs stood at USD 15/kWh as of 2018 and are expected to fall to USD 9/kWh by around 2035⁶.

In comparison, the cost of BEV batteries are expected to fall from USD 200/kWh in 2018 to USD 70/kWh by 2035⁷. BEV costs are expected to fall by about 24% by 2035 due to these lower battery prices.

Figure 10.1 illustrates how these cost reductions would impact FCEV and BEV relative prices in the passenger car market. It is clear that BEVs will be cheaper than their FCEV counterparts in 2035, even when scale and technological progress allow for significant reductions in the cost of fuel cells and hydrogen storage tanks. Albeit, the cost advantages of BEVs are expected to fall to around 21% in 2035, down from 46% in 2018. It should be noted that the cost reductions projected for FCEVs are contingent on a rapid uptake of these vehicles. In the absence of this occurrence, the price of FCEVs would not see these forecasted sharp declines. Hence, a key variable to continue to watch would be future global FCEV purchases, aside from the market prices for these vehicles.

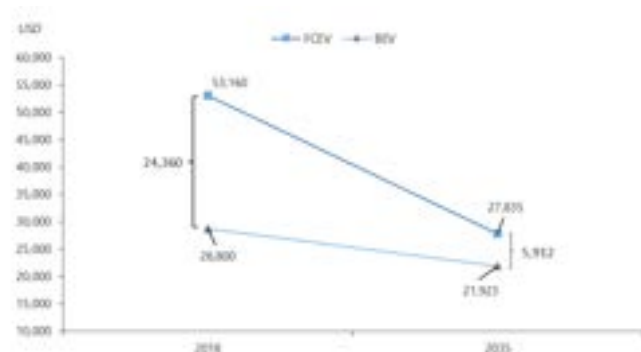


Figure 10.1 - Comparison of the Market Price of FCEVs and BEVs (Passenger Car Segment)

⁵Hydrogen Council (2020). Path to hydrogen competitiveness: A cost perspective]

⁶IEA, The Future of Hydrogen, Technology Report, June 2019.

⁷ Bloomberg NEF (2020). Hydrogen Economy Outlook.

Vehicle Types and Characteristics

In this study, five broad categories of vehicles were assessed, including private cars, taxis, LGVs, public buses and HGVs. Motorcycles and private buses were omitted from this assessment for the following reasons:

- Motorcycles: the power requirements are small and hence have little impact on the demand for hydrogen in Singapore.
- Private buses: the analysis will resemble that of an LGV or HGV, depending on the vehicle's size and seating capacity.

Private Cars

» Population and Mileage

As of 2018, Singapore had approximately 615,452 registered cars on the road⁸. Given Singapore's small geographical size, with a width approximately 50km across, and 27km north-to-south, few private cars will travel further than 100km a day. As such, mileage for private cars in Singapore average around 46 km per day.

» Refilling and Recharging

Refilling an FCEV is similar to refuelling an ICE vehicle with various refilling stations located island-wide. The time it takes to fill an FCEV hydrogen tank is comparable to the time it takes to fill an ICE tank, usually less than five minutes.

BEVs on the other hand have a completely different operating procedure, requiring substantial time to recharge (approximately 4 hours⁹). BEV drivers have been known to adopt a top-up philosophy⁹ in contrast with ICE drivers who typically refuel when their tank is less than half full. BEV charging points are typically located in public car parks, in shopping malls, office building car parks, and residential estates. Charging point widespread deployment could support more ad-hoc charging, which in turn can reduce time required for each charging cycle.

Taxis

» Population and Mileage

Singapore had approximately 20,581 taxis in operation⁹ in 2018. This is expected to decline as ride sharing services continue to grow. Taxis travel an average distance of 300km/day¹⁰ around 6.5 times more than private cars.

Most taxis (around 70%) in Singapore operate on a 2-shift, 24-hour model.

» Refilling and Recharging

Based on current operations, taxi refuelling under the split-shift model usually occurs just before the end of each 12-hour shift (typically at 5 to 6 am/pm) to meet the requirement for drivers to hand over each taxi with a full tank. Taxi drivers in Singapore usually do not have to top up during their shift¹¹. While there are no restrictions on where taxi drivers can refuel their vehicles, major taxi operators do have refilling depots where fuels are sold to taxi drivers at a discounted rate.

For taxis to transition to FCEVs, given their short refilling time, the existing operational model of using a centralised depot for refilling can be adopted. In this model, taxi drivers only refuel their vehicles once at the end of their shift. While this operational model can be retained, it should be noted that the refilling of an FCEV is 2 to 3 times longer than refilling an ICE vehicle. To prevent excessive queuing toward shift changes, twice the number of dispensers could be required, assuming all vehicles need a full refill at shift change. In addition, due to larger storage tanks needed for a hydrogen refilling stations, footprint requirements are likely to be larger than current depots.

For taxis to transition to BEV, additional time needed to charge vehicles will require taxi companies and drivers to change their concept of operation. Assuming a 50kW fast charger is used with an average distance travelled placed at 250km per shift, each taxi will require almost 1.5 hours of charging time per shift. Compared with existing petrol and potential FCEV operating models where refilling takes a few minutes, BEV charging times will demand changes to the taxi operating model in Singapore. This could also possibly lead to larger fleets needed to maintain availability. Such changes include staggering taxi shift times, and/or enabling drivers to charge while having lunch or other breaks. This will reduce the top-up/re-charging time spent at the end of each shift. For such operating concepts to be practical, 50kW chargers have to be available to taxi drivers city-wide and near places where drivers usually take breaks.

Buses

» Population and Mileage

There are more than 360 scheduled bus services operated by Singapore Bus Services (SBS) Transit, Singapore Mass Rapid Transit (SMRT) Buses, Tower Transit Singapore and

⁸ This is estimated for 'slow home charging'

⁹ LTA Website [<https://www.lta.gov.sg>]

¹⁰ elementenergy, Electric Vehicle Charging Behaviour Study, [<http://www.element-energy.co.uk/wordpress/wp-content/uploads/2019/04/20190329-NG-EV-CHARGING-BEHAVIOUR-STUDY-FINAL-REPORT-VI-EXTERNAL.pdf>]

¹¹ ComfortDelGro (CDG) Interview Notes 16th December 2019.

Go-Ahead Singapore. The Singapore Land Transport Authority (LTA) owns or leases all scheduled buses in Singapore (approximately 5,800 as of 2018). There are approximately 4 million daily rides on scheduled buses in Singapore. There are a further 19,000 private buses including minivans and full-size buses, which are not covered in this analysis.

» Refilling and Recharging

Public buses run from 5:30 am until midnight every day, with several night bus routes operating from midnight until 2:00am on Fridays, Saturdays and nights before public holidays¹². All buses return to bus depots at the end of revenue services for cleaning, garaging and servicing. There are currently 15 bus depots and bus parks in Singapore.

For complete electrification of Singapore's scheduled bus fleets and assuming it takes the full window to completely recharge a single bus, 6,000 recharging points will be required to match the number of buses. Level 3 DC fast charging can more than halve the charging time; however, the number of recharging points remains substantial, while logistics remain challenging. BEV buses will require in excess of 90 minutes to fully charge using a Level 3 DC fast charger.

With a much shorter hydrogen refilling time requirement for FCEV buses, it would be possible to refill more than 20 buses in a four-hour window from a single refilling point. The logistics are similar if not identical to those for the existing diesel bus fleet. With FCEV buses, the opportunity to refill during the day also exists.

FCEV bus refilling times are approximately 10 minutes, compared with 3 to 4 minutes for existing diesel bus fleets. This will result in longer overnight refilling times, and/or additional dispenser numbers. Therefore, it is likely that FCEV bus depots will have larger footprint and additional separation distance requirements.

Light Goods Vehicles

» Population and Mileage

Of the 96,968 LGVs in Singapore as of 2018¹³, less than 4% are fuelled by petrol. Diesel remains the fuel of choice for this category of vehicles similar to the HGV category. The penetration of hybrids and electric LGVs are similarly quite low. Singapore LGVs travel around 80km/day on average.

» Refilling and Recharging

BEV LGVs will likely require depot charging, with approximately 15 minutes of charging per day on average using 100 kW chargers. FCEV LGVs will require longer overnight refilling periods and potentially larger depot and HFS footprints. FCEV LGVs will require approximately 6 minutes for a complete refill, compared with 3 minutes currently for ICE LGVs.

Heavy Goods Vehicles

■ Population and Mileage

As of 2018, Singapore had approximately 46,123 registered HGVs on the road¹⁴. These vehicles travelled close to 110km/day on average. HGVs need to be parked in designated parking spaces when not in use. The bulk of these vehicles (around 97%) are fuelled by diesel with the rest being gasoline-fuelled.

» Refilling and Recharging

BEV HGVs will likely require depot charging, with approximately 35 minutes of charging per day on average using 250 kW chargers. FCEV HGVs will reflect the same trends as for buses, with longer refilling periods overnight and potentially larger depot footprints. FCEV HGVs will require approximately 10 minutes for a complete refill, compared with 4 minutes currently for ICE HGVs.

Vehicle Market Trends

FCEVs in the private car segment have faced adoption concerns since Toyota produced its first commercial version in 2014¹³. Two issues have impacted sales: namely, high purchase costs as well as a lack of refuelling infrastructure. As of 1 August 2020, there were 8,475 cars sold and leased in the US. As of 1 November 2019, Japan had 3,521 cars sold or leased¹⁴. The expectation is that these numbers would rise as infrastructure becomes more ubiquitous, and as vehicle prices fall due to increased scales of production and technological progress. However, the challenge from BEVs is expected to be stiff.

FCEVs are expected to do better in larger vehicle categories, such as buses and trucks, relative to BEVs. Battery size limitations for heavy vehicles limits the range and/or payload capacity for such vehicles especially HGVs.

¹² LTA Website [<https://www.lta.gov.sg>].

¹³ IEA Technology Collaboration Programme (2020). Mobile fuel cell applications: Tracking market trends.

¹⁴ <https://www.greencarcongress.com/2019/05/20190525-dhl.html>.

Breakeven Prices

Basis and Assumptions

Hydrogen breakeven points for the mobility sector provides the price of hydrogen to be the same as the technology that it's being compared against, such as conventional ICE technology, ICE hybrid technology and BEV technology.

For each transportation category (private car, public buses taxi, HGV and LGV), vehicle models which are currently available in the market are used to determine the technical specifications and cost parameters assumed in this analysis. This includes fuel economy, carbon emissions, battery power ratings and purchase costs (including taxes) which form the basis to develop a cost of ownership model for the various types of technologies. The base year for the model is 2018. The cost reported are in 2018 US dollars unless otherwise stated. Table 10.1 documents the general assumptions for the mobility breakeven calculations.

Table 10.1 - General Assumptions for Mobility Breakeven Calculations

PARAMETER	UNITS	PRIVATE CARS	TAXI	LGV	HGV	PUBLIC BUS
Asset Life ¹	Years	10	8	10		17
Annual Mileage ²	km/year	17,500	110,245	29,500	39,500	66,717
Discount Rate	%	4%				
Manufacturer Markup	% of Car Market Value	20% (all vehicles except buses), 25% (buses)				
Distributor Markup	% of total CAPEX	15%				Assumed no distributor involved for public vehicle

Notes:
¹ Asset life is assumed to be the full 10-year COE period for the vehicle or its statutory lifespan.
² LTA Website [https://www.lta.gov.sg]

Table 10.2 provides projected fuel price points required by each vehicle type used for the calculation. The fossil fuel (petrol, diesel and natural gas) and electricity price outlook to 2050 are projected using Argus's in-house modelling tools. For fossil fuels, the price is taken at the fuel pump and any costs between the raw fuel such as retail mark-up and logistics are accounted for within prices. For

hydrogen fuel and electricity, prices are assumed to be at wholesale levels, based on the landed cost model and Uniform Singapore Electricity Prices (USEP) respectively. To accurately compare prices at the dispensed outlet with pump prices, a fuel or electricity mark-up as well as distribution costs are added.

Table 10.2 - Assumptions on Fuel Prices for Breakeven and Levelised Cost of Transportation (LCOT) Calculations

TECHNOLOGY	SUB-CATEGORY	UNITS	VALUE				BENCHMARK
			2020	2030	2040	2050	
Fuel prices at pump	Petrol	USD/L	1.60	1.66	1.72	1.71	Shell Fuelsave 95, projection adjusted using Argus Petrol prices
	Diesel		1.37	1.37	1.44	1.42	Shell Fuelsave Diesel, projection adjusted using Argus Gasoil prices
Electricity	Electricity USEP	USD/MWh	125	126	1.21	114	USEP, projection adjusted using Argus natural gas forecast
	Electricity Markup	%	10%				
Hydrogen	Hydrogen Wholesale Price	USD/kg H ₂	6.32	4.90	4.12	3.83	Landed Cost of Hydrogen
	H ₂ Retailer Markup	%	20%				Assumed to be same as petrol markup without taxes

Levelised Cost of Transportation and Breakeven Price Analysis Private Cars

Figure 10.2 illustrates the levelised cost of transportation (LCOT)¹⁵ for FCEVs and BEVs in the private car category. It should be noted that the LCOT for analysis includes fuel costs as well as infrastructure costs. Over the outlook period, BEVs have a lower LCOT than FCEVs for private cars.

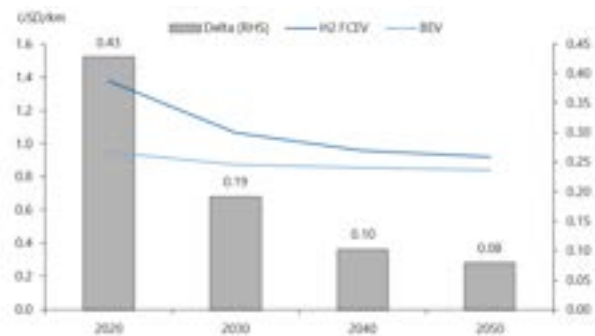


Figure 10.2 - Private Cars – LCOT Comparison (FCEVs vs. BEVs)

¹⁵ The LCOT is a normalization of the cost of ownership of a vehicle over its lifetime on a per kilometer basis.

For private cars, upfront costs are impacted significantly by taxes on ownership. This result in capital costs¹⁶ by 2050 contributing close to 70% of LCOT, while ownership taxes account for three quarters of the capital cost.

Figure 10.3 illustrates the breakeven price (denoted by the bars) for FCEVs compared to BEVs, ICE petrol and ICE petrol-hybrids in the private car segment. The breakeven price calculation gives us the price of hydrogen at which an FCEV would be competitive against other vehicles in the study. It should be noted that infrastructure costs are likewise taken into consideration in breakeven price calculations for the entire analysis. Over the outlook period (2020 to 2050), the price of hydrogen required to make the total cost of ownership of an FCEV equivalent to its competitors is negative and uneconomical from a breakeven price perspective.

Thus, in the private car category, FCEVs would likely struggle to compete economically with both ICEs and BEVs in 2050 given the projected landed cost of hydrogen. Two factors contribute to this result:

- The capital cost of FCEVs is much higher than their BEV and ICE equivalents. This is further aggravated by extant taxes, such as the ARF; and
- The intensity with which private cars are driven in Singapore, around 17,500 km/year on average, is on the lower side. Hence, the savings on an operating cost (especially against ICE vehicles) basis do not compensate for higher upfront capital cost.

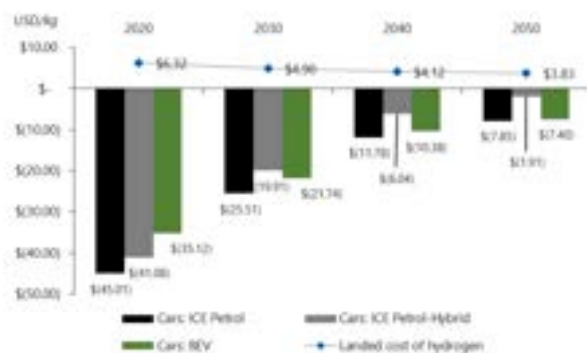


Figure 10.3– Private Car Breakeven Price

Taxis

As in the case of private cars, Figure 10.4 illustrates the LCOT for FCEV and BEV taxis. The gap between the LCOTs in 2050 is less than that for private cars given higher intensity with which taxis are driven compared with private cars, and also where a higher CAPEX can be spread-out.

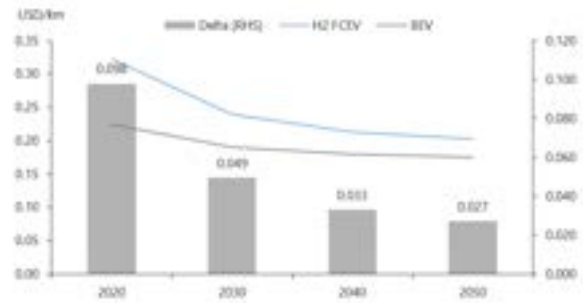


Figure 10.4 - Taxis – LCOT Comparison (FCEVs vs. BEVs)

Figure 10.5 illustrates the breakeven price for FCEVs against BEVs, ICE diesels and ICE petrol-hybrids in the taxi segment. Breakeven prices for FCEV taxis are more viable against ICE diesel and ICE hybrid technologies, with the expected price of hydrogen at the dispenser reaching this break even price as early as 2040. Compared to the private car segment, this result is again a function of the high mileage of taxis relative to private cars. With average driving distances being close to six times that of a private car, taxi owners have observable savings from switching to vehicles with lower operating costs. However, FCEVs are still not competitive against BEVs even in 2050 given low operating costs of BEVs. In 2050, the breakeven price of hydrogen for FCEVs compared to BEVs in the taxi segment is negative USD 0.38/kg hydrogen.

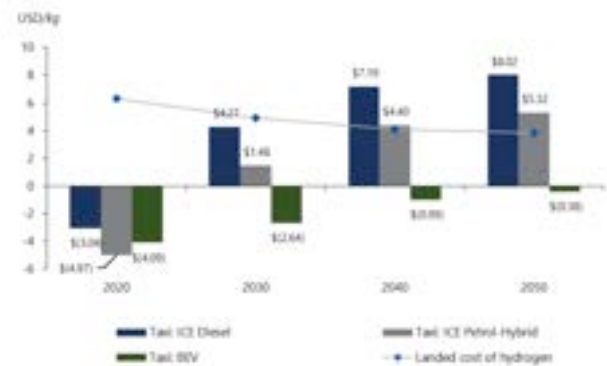


Figure 10.5 – Taxi Breakeven Price

Public Buses

Figure 10.6 illustrates the LCOT for FCEV buses and BEV buses over the outlook period. The gap between the cost of owning and operating the two vehicle types is projected to fall significantly over the outlook period, narrowing the LCOTs difference to USD 0.03/km by 2050.

¹⁶ Capital cost here refers to the upfront cost of the car. This includes the market value of the car, the ownership taxes and distributor markups. Fixed cost here refers to the sum of annualized costs that recur every year/half a year. The fixed cost thus includes car servicing (maintenance), season parking, car insurance, road taxes, special taxes and fuel excise duties.

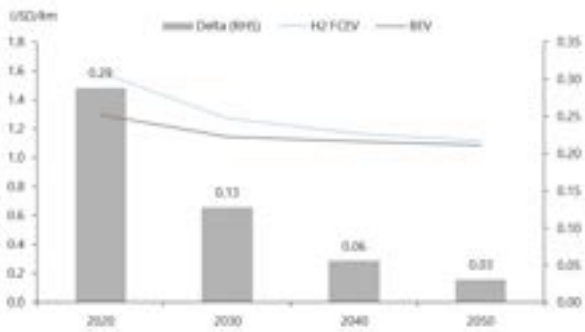


Figure 10.6 - Buses - LCOT Comparison (FCEVs vs. BEVs).

Figure 10.7 shows the breakeven analysis for buses. FCEV buses are projected to be competitive against ICE diesel by 2040 and ICE diesel-hybrid by 2050 due to decrease in hydrogen bus upfront cost as well as hydrogen fuel. Fuel costs form a substantial part of the running costs for public buses given that they travel close to 66,717 km/year, which gives them a competitive edge against ICE buses.

It should be noted that BEV buses have a higher breakeven price compared to private cars and taxis. This is primarily due to high mileage and power requirements (due to the heavy weight) for buses as compared to lighter vehicles, thereby requiring BEV buses to have larger battery capacity. This in turn increases the CAPEX cost of BEV buses and correspondingly increases its breakeven price.



Figure 10.7 - Public Bus Breakeven Price

Light Goods Vehicles

Figure 10.8 compares the LCOT of FCEV and BEV LGVs over the outlook period. Similar to other vehicles, the LCOT gap between the FCV and BEV decreases over the outlook period but does not completely diminish.

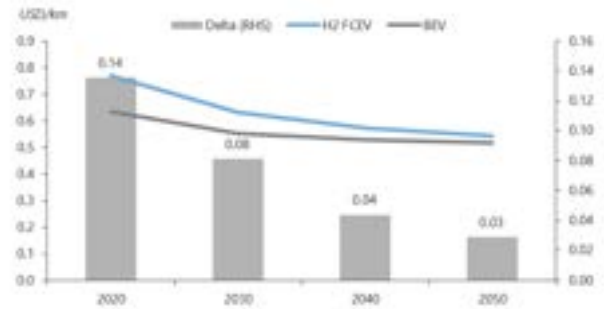


Figure 10.8 - LGVs - LCOT Comparison (FCEVs vs. BEVs)

Breakeven price analysis, as shown Figure 10.9, FCEV is projected to be competitive against ICE diesel and ICE petrol equivalent by 2050 given the FCEV CAPEX reductions and hydrogen prices. FCEVs will however still be unable to compete with BEVs even by 2050.



Figure 10.9 - LGVs Breakeven Price

Heavy Goods Vehicles

The HGV category is the only one where FCEVs are projected to be more economically viable than its BEV counterparts by 2050. As illustrated in Figure 10.10, cost parity occurs between 2043 and 2044. The high-power rating required for HGV results in large battery capacity requirements, substantially raising costs. With the decline in the cost of fuel cell systems, upfront costs for FCEV HGV is expected to fall below BEV HGV, giving it a competitive edge.



Figure 10.10 – HGVs - LCOT Comparison (FCEVs vs. BEVs)

As shown in Figure 10.11, in 2050, the breakeven price of a FCEV HGV truck relative to its BEV HGV competitor is USD 5.04/kg hydrogen with the cost rising to USD 6.65/kg hydrogen for the ICE diesel equivalent. As noted in the study's landed cost section (Section 6), there are a number of locations that might be suitable for hydrogen import at a lower price than these breakeven values. This makes the HGV segment one of the niche applications in the transportation sector where hydrogen can be competitive with the alternatives in the long run.

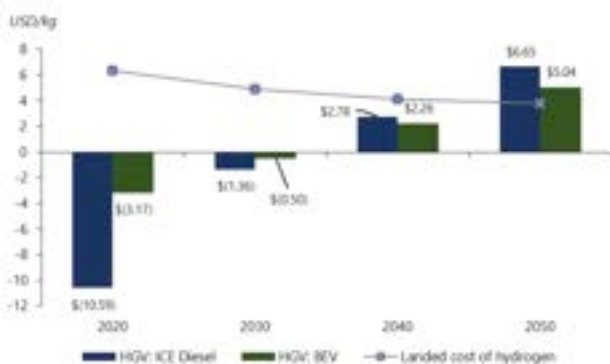


Figure 10.11 – HGV Breakeven Price

Signposts to Monitor

From the LCOT and breakeven analysis of vehicle categories, FCEVs are not likely to be competitive with their BEV counterparts over the forecast period, with the exception of HGVs that become competitive with BEVs around 2043-2044. A sensitivity analysis conducted separately shows FCEV capital costs in all categories as having the most significant impact on relative ownership economics and competitiveness against BEVs. Therefore, if technical progress and economies of scale positively lowers FCEV upfront costs from that projected in the analysis, outcomes could change, especially for public buses¹⁷, as well as LGVs to a smaller extent. Based on this, signposts to monitor include the variance in capital cost and the global uptake of:

- HGVs;
- Public buses; and
- LGVs, with particular interest in LGV fleet services.



¹⁷ For instance, were the upfront costs of owning a hydrogen HGV to rise by 30% (from the base case value) in 2050, the breakeven price would fall to USD1.57/kg hydrogen. This would make hydrogen HGVs unviable as the landed cost of hydrogen will most likely be well above that breakeven price value in 2050.

Mobility Scenario Overview

From the information gathered to date and stakeholder consultations and workshops in which various hydrogen deployment scenarios were tabled, Table 10.3 represents three possible hydrogen adoption scenarios for the Singapore mobility sector as well as two boundary cases of 100% BEV and 100% FCEV adoption for comparison.

Table 10.3 – Mobility Scenarios for 2050

Scenario	BEV	Low	Medium	High	FCEV
Private Cars ¹	100% BEV				100% FCEV
Taxis	100% BEV	100% BEV	20% FCEV	50% FCEV	100% FCEV
Buses ²	100% BEV	100% BEV	40% FCEV ²	50% FCEV ²	100% FCEV
Light Goods Vehicles	100% BEV	100% BEV	10% FCEV	20% FCEV	100% FCEV
Heavy Goods Vehicles	100% BEV	100% FCEV			

Notes:

¹ The Private Cars category includes private hire cars (e.g. GrabCar).
² The adoption of public buses in medium and high scenarios require FCEV technological advancement and significant cost reduction in the near term. This will allow sufficient lead time to develop the necessary infrastructure at bus depots.

The infrastructure required for these scenarios has been estimated and is provided in the subsequent section. As well as providing visibility for anticipated investment required for each scenario, these CAPEX figures are incorporated into the vehicle breakeven costs and carbon abatement costs for each vehicle category. Averages based on per vehicle cost are used as the basis.

Mobility Infrastructure CAPEX Analysis

Infrastructure cost is a significant factor in BEV deployment compared to FCEVs. Although BEV recharger unit costs are considerably lower than for FCEV dispensers, it is more expensive on a per-refill basis because of recharge times for BEVs.

Overall Scenario Analysis

From a high-level perspective, an FCEV-based economy would look similar to the existing fuel-based economy, with centralised refilling outlets (service stations) and private refilling depots for taxis, buses and industrial vehicles. The main difference would be higher volumes of distribution trucks (more than double the number of daily deliveries) required to maintain hydrogen stock at service stations and depots. This is largely because of reduced fuel storage capacity at service stations when dealing with hydrogen, as well as the reduced payload per delivery. There will also be additional land requirements for terminals and service stations.

A BEV-based economy will look quite different, with substantially more recharging points required and changes in driver behaviour towards top-up charging, particularly from home.

The scenarios presented were examined to determine infrastructure requirements and resultant costs. All infrastructure cost estimates exclude land costs and are based on 2018 CAPEX figures and currency value. Table 10.4 shows the three scenarios examined in terms of overall FCEV and BEV adoption rate.

Table 10.4 – Mobility Scenarios and Overall FCEV/BEV Adoption for 2050

Scenario	Low	Medium	High
FCEV Adoption (Cumulatively for All Vehicle type)	4%	6%	8%
BEV Adoption (Cumulatively for All Vehicle type)	96%	94%	92%

The total number of BEV chargers required for the 100% BEV Scenario is in the order of 177,000, of which:

- 128,500 are expected to be residential;
- 13,000 are expected to be situated in fleet depots (commercial); and
- 35,500 are expected to be non-residential and non-depot (e.g. shopping malls, public car parks and office buildings).

Figure 10.12 shows the number of BEV chargers and FCEV dispensers that will be required for the different scenarios in 2050. Approximately 164,000 publicly available BEV chargers (including residential) will be required for the 100% BEV Scenario. This number is above the 28,000 chargers targeted by the Singaporean government in March 2020 for deployment at public car parks by 2030¹⁸. In comparison, approximately 1,900 publicly available FCEV dispensers will be required in 2050 under the 100% FCEV adoption scenario. This can be compared with the 1,100 ICE fuel dispensers that are currently available to the public in Singapore service station forecourts. The remaining 1,000 FCEV dispensers for the 100% hydrogen scenario will be located in truck, bus and taxi depots.



Figure 10.12 – Number of Publicly-available BEV and FCEV Dispensers in 2050

For BEVs, beyond just the deployment of charges, it is important to understand the impact on Singapore's electrical grid. For example, for every 50,000 BEVs topping up with a slow-speed 7.4 kW charger, at the same time an additional 370 MW of power demand will be placed on local electricity infrastructure in residential areas and the power generation sector. While it is too early to estimate how this energy demand will impact the daily peak power demand, this provides perspective on the scale of additional load on existing electricity infrastructure and the potential need for additional infrastructure. It should be noted that faster chargers will reduce charging times and alleviate the demand for BEV charging infrastructure, while at the same time potentially introducing power demand peaks of a greater scale. To understand the full impact BEV charging will have on Singapore's electricity grid, it is important that the scale, distribution and concentration of charges, and additional grid loads are carefully modelled which is beyond the scope of this study. Any large-scale adoption of BEVs across one or more of the vehicle categories may result in the need for electricity grid upgrades.

Mobility Sector Electricity and Hydrogen Demand

Table 10.5 shows the forecast electricity and hydrogen consumption for 2050 under the scenarios examined, against the forecast fossil fuel consumption, assuming that the predominant ICE status quo remains.

Table 10.5 – Mobility Scenario Fuel Consumption for 2050

Scenario	Status Quo	BEV	Low	Medium	High	FCEV
Fossil Fuels (kbbt/annum)	16,000					
Electricity (TWh/annum)	0.14	8.94	5.12	4.34	4.00	
Hydrogen (ktpa)		0	151	190	209	429

Singapore's mobility sector electricity consumption is estimated at approximately 9.0 TWh per annum for 100% BEV adoption by 2050, and ranges between 4.0 and 5.0 TWh per annum for low, medium, and high scenarios. Given the distinct charging patterns for different vehicles (e.g. buses at night-time, taxis on a split-shift pattern and private cars with relatively even spreads), the impact EV charging can have on daily peak electricity demands can vary significantly. Detailed studies will have to be conducted to evaluate this further.

Singapore mobility sector's hydrogen demand is estimated at approximately 430 ktpa for hypothetical 100% FCEV adoption by 2050, and ranges between 150 and 210 ktpa for the different deployment pathways.

Safety and Regulatory Considerations

It is widely understood that the storage, transportation, handling and use of hydrogen as a mobility fuel carries a different risk profile than that of traditional fossil fuels.

For example, leaking hydrogen in the open will rise quickly. However, in an enclosed area, hydrogen could collect within ceiling areas where there are no easy horizontal ventilation pathways (as is the case in tunnels and covered/multi-storey car parks) and where ignition of this trapped hydrogen vapour cloud could result in explosion. This is one of the most significant hazards when dealing with hydrogen.

¹⁸ Singapore has since increased its charger deployment target to 60,000 chargers by 2030

Careful review and adoption of the policies and protocols introduced from other hydrogen mobility economies such as the US state of California, South Korea or Japan may be the most suitable path forward for ensuring that FCEVs can be introduced into Singapore safely and at reasonable cost. Singapore can also draw from its experience in deploying and setting safety regulations for CNG vehicles. Similar to hydrogen, CNG is also lighter than air and will exhibit the same behaviours (but to a lesser degree).

Safety Regulations

Safety regulators in Singapore will need to consider the following aspects in relation to the introduction of FCEVs:

A set of licensing requirements must be in place to ensure that hydrogen is being safely stored;

- The storage or use of hydrogen must be supported by stringent fire safety precautions and mitigations; there must be provisions in place to mitigate any fire in the first instance;
- Plants and facilities that are storing hydrogen must follow the QRA process and implement all recommendations to ensure that high-risk events do not cascade onto the entirety of the facility;
- Implemented fire safety measures must comply with international standard codes of practice; and
- Entities seeking to store and/or use hydrogen must apply for and hold a licence to operate the fuel, ensuring that adequate fire safety measures are installed and functioning. This licence will need to be renewed on an annual basis, as with all other hazardous materials such as petrol and diesel.

There is also a need to review current hydrogen regulation processes while maintaining safety requirement levels. Currently, a Quantitative Risk Assessment (QRA) study is required for the relevant facilities, while the SCDF is the authority responsible for the QRA process for such facilities:

- The SCDF does not impose a blanket restriction on hydrogen transportation and storage pressure; and
- Quantitative Risk Assessment criteria is more stringent where sensitive receptors (such as government buildings) are nearby, and where the facility is vital to Singapore's security and critical infrastructure.

In addition, dangerous goods including hydrogen, are prohibited by legislation to be transported through tunnels or nearby sensitive receptors. Therefore, a review

of current hydrogen regulations and processes should be a critical next step by Singapore regulators when considering the introduction of hydrogen mobility.

As mentioned earlier, given the number of successful FCEV deployment examples which exist in Europe, US and developed Asian nations, it is recommended that Singapore takes an adopt-review-amend approach from elsewhere. The California FCEV regulation framework may be a good example where Singapore can draw parallels from.

Public Safety

Concerns revolve around public safety, while there are varying degrees of misperception on concerning hydrogen safety as a replacement for road transportation fossil fuels.

The most common public concern is FCEV safety and their occupants in the event of a vehicle cabin hydrogen leak. FCEV manufacturers conduct extensive safety testing similar to that used for traditional ICE vehicles. There are various safety features incorporated into FCEV hydrogen containment system designs to minimise the likelihood of fire or explosion, and the consequences thereof¹⁹. This can be coupled with the extremely light nature of hydrogen as a leaking gas, which causes it to disperse from the immediate area quickly, either during or prior to the fire and explosion point.

Further RD&D is being conducted globally into hydrogen release and ignition in confined spaces such as tunnels and covered car parks. The progress of such studies should be monitored with the results integrated into any existing or future legislation.

Regulatory Path Forward

Establishing a series of regulations is a critical first step in introducing hydrogen into Singapore's mobility sector. Although it does not prevent the introduction of small-scale FCEV trials, it allows for more substantial trials and permanent adoption of FCEVs to take place because of the investment security that an established set of regulations would provide. Without regulation, investment beyond small-scale trials may incur headwinds.

As part of FCEV regulation establishment, vehicle inspection and maintenance will also need to be reviewed because existing inspection frequencies and scopes are designed for petrol and diesel which have a different risk profile to that of hydrogen.

¹⁹ Hyundai, How Safe are FCEVs?, [<https://news.hyundaimotorgroup.com/Article/How-safe-are-Fuel-Cell-Electric-Vehicles>]

Conclusions and Recommendations

Overview

Hydrogen deployment pathways reflect a greater uptake for BEVs over FCEVs within Singapore due to the lower on-road costs. This is especially so for private cars which make up more than 60% of all vehicles on Singapore roads.

Private Cars

For private cars in Singapore, there is no clear advantage of FCEVs over BEVs due to their low mileage and more attractive BEV breakeven/on-road cost (e.g., in 2050, the price of hydrogen would have to be negative USD 7.40/kg for an FCEV to compete with a BEV). It is recommended that Singapore focuses its private car transition on BEVs and associated infrastructure. Under a BEV model and the expected deployment pathways, BEV private cars will account for between 60% and 80% of the expected overall infrastructure investment required.

Taxis

Taxis travel the greatest average distance of all vehicle categories in Singapore, and hence are subject to more recharging/refilling time considerations. FCEV is best suited to existing taxi split-shift operating models because of comparable refilling times compared to ICE vehicles, while adoption of BEVs will dictate a change to a more distributed fleet recharging model in order to compensate for high recharging times. This is not seen as an obstacle to BEV adoption, but rather a consideration to be carefully managed by taxi fleet operators. To maintain current on-road presence and revenue, taxi fleets might need to be 8% larger when compensating for BEV recharge time using Level 50 kW chargers. It is recommended that taxi fleet operators consider vehicle range, refilling/recharging time, vehicle fleet size and shift change management when considering a transition to BEVs and/or FCEVs.

Buses

The average daily mileage of a public bus in Singapore ranges between 95km and 320km. With a 50kg hydrogen tank, an FCEV bus will have an approximate range of 400km and a refilling time of a few minutes, while a BEV bus fitted with a 350 kWh battery will travel 250km and require in excess of 1.5 hours to charge using a 250 kW

charger. Existing BEV bus chargers installed in Singapore range from 90 kW to 150 kW²⁰. The breakeven price of hydrogen needs to be USD 2.39/kg (or below) by 2050 for a hydrogen bus to compete with its BEV equivalent. It is recommended that bus fleet operators maintain a careful view on BEV battery and charger developments and trends for heavy vehicles, and carefully examine the number of chargers required to maintain the existing night-time recharging model.

Light Goods Vehicles

LGVs are expected to be predominantly BEVs. LGVs have a shorter daily range relative to taxis and buses and hence are better able to capitalise on lower BEV breakeven costs with minimal adverse impact on operation and operating models. It has been assumed that BEV LGVs will require depot recharging, while FCEV LGVs would be able to refill at present public HFSs.

Heavy Goods Vehicles

Across all three considered deployment pathways, HGVs are projected to transition to FCEVs. This is driven by impractical large and heavy on-board batteries required to deliver the corresponding power and range needed. FCEV HGVs are expected to refill at dedicated depots, and account for 6% of the required infrastructure investment for the anticipated deployment pathways. In terms of breakeven prices, cost parity between the hydrogen and battery HGVs is expected around mid-2040.

Land Requirements

Average space for a service station in Singapore is around 2,000m² while the total land area for the 186 existing public service stations is estimated to be 380,000m². Equivalent hydrogen demand assuming complete transition to FCEV would require a land area of 1,600,000m². Larger HFSs of approximately 2,000kg/day will have a smaller footprint per kg/day of output. However, the conversion of existing service station sites to HFSs and the absence of available surrounding space may limit the size of HFSs to 800kg/day unless separation distance and/or transaction time can be reduced. Within anticipated deployment pathways, hydrogen depots will be required for FCEV taxis, buses and trucks, while private cars are assumed to be 100% BEV.

²⁰ Email from Stuart Thomas, K857 - KBR and Tower Transit Follow-up, 1st April 2020

11

Industrial and Manufacturing

"Low-carbon hydrogen feedstock adoption and its use as a fuel source could support industry decarbonisation efforts; however, breakeven prices remain challenging throughout the outlook period for the industrial sector."



Hydrogen as Feedstock

Hydrogen is a crucial feedstock for Singapore's oil refining and petrochemical industries. The industry produces brown hydrogen in dedicated SMR units and as a by-product of other processes. The industry is hydrogen deficient and purchases brown supplemental hydrogen from merchants.

Throughout the study, KBR engaged industry stakeholders regarding the adoption of low-carbon hydrogen to help decarbonise their operations. Stakeholders expressed cost concerns and how this could undermine Singapore's competitiveness in the region. Stakeholders also shared their global sustainability and decarbonisation efforts, including studies on hydrogen value chain optimisation, assessing the economic benefits of domestic low-carbon hydrogen production versus imported blue/green hydrogen. However, none of the stakeholders interviewed announced concrete decarbonisation plans using low-carbon hydrogen.

Options evaluated include both domestic low-carbon production and imports; summarised in Table 11.1.

Table 11.1 – Potential Options for Low-carbon Hydrogen Supply in Singapore

Option	Options to Replace Industrial Brown Hydrogen	Production Pathways	Production Location
1	Blue hydrogen	Fossil-based production (SMR or residue gasification) with CCUS	Local production with CCU or CCS
2	Hydrogen from biomass feedstock	Biomass feedstock to hydrogen	Local production
3	Hydrogen from methane pyrolysis	Methane pyrolysis	Local production
4	Imported green or blue hydrogen	Hydrogen produced from renewable sources or from fossil-based production with CCUS and liquefied or chemically bonded to a carrier for transportations purposes	Imported liquefied hydrogen or hydrogen carriers with on-site regasification (for liquefied hydrogen), or dehydrogenation and purification (as required for carriers)

Option 1 considers replacing purchased merchants' hydrogen with locally produced blue hydrogen. This will require the retrofitting of existing SMR and gasification units with carbon capture equipment. Hydrogen could also be produced in residue gasification units with carbon capture technology. Table 11.2 shows a summary of the analysis.

Table 11.2 – Blue Hydrogen Analysis

Option 1 – Blue Hydrogen (local production)	
Production Pathway	Local production from fossil fuel feedstock with CCUS, SMR or residue gasification technology with CCUS.
Hydrogen Production Cost, USD	SMR SMR and CCS SMR and CCU 1.28 (2020), 1.34 (2030), 1.32 (2040), 1.30 (2050) See Figure 11.1 2.13 (2020), 2.19 (2030), 2.16 (2040), 2.14 (2050) 3.01 (2020), 3.07 (2030), 3.04 (2040), 3.02 (2050)
Risks	Currently no clear path to utilise or store the carbon in Singapore.
Advantages	Least disruptive option. Supplemental hydrogen production will remain local and integrated with the industry.
Barriers	CAPEX required for units retrofitting. Carbon storage limitations in Singapore. Requires carbon tax incentives for commercial viability. Unclear carbon utilisation pathway.
Safety	Hydrogen deployment in the industry sector is mature with well-documented safety standards. In order to capture the carbon emissions from the SMR or residue gasification plants, merchants are required to retrofit existing units following the industry's safety standards and regulations.
Technology Readiness	Mature technology
Carbon Abatement in Singapore, %	93 - 95
Indicative Land Requirements ¹ , km	0.0048 (CC) / 0.0109 (SMR)
Indicative CAPEX, USD / ton of CO ₂	98 for CCS and 200 for CCU ²

¹ Estimated land requirement for retrofitting an existing SMR unit with post-combustion carbon capture and a compression of approximately 40,000 kg of CO₂ per hour capacity.

² Assuming mineralisation as utilisation pathway. Includes carbon capture cost, landfill cost avoidance and discount due to product revenue. [Navigant, Carbon Capture, Storage and Utilisation: Decarbonisation Pathways for Singapore's Energy and Chemical Sectors, prepared for EDB and NCCS].

Option 2 considers the possibility of using renewable sources such as agricultural residues, sewage, municipal solid waste, animal residues or forestry residues for indigenous hydrogen production. Table 11.3 shows a summary of the analysis.

Table 11.3 – Hydrogen from Biomass Feedstock Analysis

Option 2 – Hydrogen from Biomass Feedstock	
Production Pathway	Biomass gasification using wood pallets as feedstock.
Hydrogen Production Cost, USD	2.20 (2020), 2.21 (2030), 2.22 (2040), 2.20 (2050) See Figure 11.1
Risks	Insufficient availability of biomass renewable local feedstocks.
Advantages	Creating value from traditional waste streams. Maintains local industry integration and synergy.
Barriers	Procuring biomass from outside of Singapore. Feedstock supply security. Assumed high hydrogen projected production costs when compared to SMR and SMR with CCS.
Safety	No major concerns have been identified as the process is mature and follows the industry safety standards.
Technology Readiness	Mature technology
Carbon Abatement in Singapore, %	100
Indicative Land Requirements ³ , km	0.049
Indicative Estimated CAPEX, USD	231,638,216 for a 51 ktpa hydrogen production facility.

Notes:

¹ Indicative land requirement based on a 6.2 ktpa hydrogen production facility.

Option 3 considers hydrogen from methane pyrolysis. In methane pyrolysis, hydrogen is split into gaseous hydrogen and solid carbon and requires an outlet for the 3kg of carbon produced per kg of hydrogen. The summary of the analysis of methane pyrolysis technology to replace brown hydrogen is given in Table 11.4.

Table 11.4 – Methane Pyrolysis Analysis

Option 3 – Hydrogen from Methane Pyrolysis	
Production Pathway	Methane pyrolysis using natural gas as feedstock to produce gaseous hydrogen and solid carbon.
Hydrogen Production Cost, USD	5.89 (2020), 4.65 (2030), 3.29 (2040), 2.24 (2050). See Figure 11.1
Risks	Technology is in early stages of development. Solid carbon product needs off-taker to make the process economically viable. Potential economic risks associated with carbon market developments and process economic feasibility.
Advantages	Low-emission hydrogen and synthetic carbon production technology. Significant carbon footprint reduction. Off-gases from oil refineries could potentially be used as feedstock to produce hydrogen instead of being used as fuel (for small volumes). Makes use of existing NG infrastructure. Maintains local industry integration and synergy.
Barriers	Scalability and production costs prices. Carbon sales prices or cost for storage is critical for process to be economically viable. Large-scale industrial deployment has yet to take place. Solid carbon market is not a market in which Singapore is currently involved and it could pose a barrier if it cannot be accessed. Biogas source supply security. Technology development challenges. Biogas or renewable electrical heating is required to achieve low-carbon emissions claimed by the process.
Safety	The methane pyrolysis process has been deployed in the past with the focus of producing carbon. Large deployment to produce hydrogen has not yet taken place; however, the industry methane adoption is mature and follows the industry safety standard. Further R&D and technology maturity will be required to demonstrate the process scalability and safety.
Technology Readiness	Early development stages. 3 – 7 TRL.
Carbon Abatement in Singapore ³ , %	50 - 100
Indicative Land Requirements ⁴ , km	Not available
Indicative CAPEX ⁵ , USD	15.5 million

³ According to the HAZER Group, hydrogen produced via methane pyrolysis from non-bio sources would result in 50% of the SMR emissions [71]. This emission factor has been used for this study as the HAZER process has the highest TRL of all the technology groups approached for methane pyrolysis. Other processes such as BASF and Engie report zero emissions if green electrical energy heating is applied, but the processes are far from scaling or commercialisation.
Hazer Process, [https://www.hazergroup.com.au/about/]

The quest for CO₂ free hydrogen, methane pyrolysis at scale, William Daloz, Frederik Scheiff, Kai Ehrhardt, Dieter Flick, Andreas Bode, Reaction Process Engineering, BASF, [https://arpa-e.energy.gov/sites/default/files/1%20Scale%20up%20BASF.pdf].

⁴ The stakeholders interviewed for this study could not provide estimated land requirements for a commercial methane pyrolysis unit given the early TRL of the technology and design variables that will have an impact on the land requirements.

⁵ CAPEX is based on a 100 tpa hydrogen production facility and HAZER technology.

Option 4 assumes importing hydrogen produced from renewable sources or from fossil-based production with CCUS and liquefied or chemically bonded to a carrier for transportation purposes. Hydrogen could be re-gasified or released from the carriers in a centralised manner and then supplied to the industry. For the purpose of this report, it has been assumed that the centralised distribution facility can be potentially shared with other sectors, such as power generation. Table 11.5 shows a summary of the analysis.

Table 11.5 – Imported Green or blue Hydrogen Carriers

Option 4 – Green or Blue Hydrogen Carriers	
Production Pathway	Hydrogen production from renewable energy sources or from fossil-fuel feedstock with CCUS. Hydrogen is transported to Singapore using one of the selected carriers for the study.
Hydrogen Production Cost, USD	6.32 (2020), 4.90 (2030), 4.12 (2040), 3.83 (2050) See Figure 11.1
Risks	Large market disruption where merchants could potentially lose hydrogen market in Singapore. Storage may be required to ensure hydrogen supply security for the industrial sector.
Advantages	Centralised receiving and distribution facility for the industry via pipeline. Hydrogen liberation could also be decentralized. Zero carbon emissions in Singapore related to hydrogen production ⁶ .
Barriers	Hydrogen costs pose a major roadblock for adoption in the industrial sector. The technical barriers of each carriers are discussed in detail in Section 5.
Safety	Hydrogen to be imported and deployed in the industry which has well-documented safety standards for hydrogen handling.
Technology Readiness	The technology associated to the carriers considered in this study are considered mature across the supply chain with the exception of storage and transportation of liquefied hydrogen. See Section 5 for more information.
Carbon Abatement in Singapore ⁶ , %	100
Indicative Land Requirements ⁷ , km	Receiving facilities for the carriers and distribution pipeline (shared with power generation). See Section 13 for more information.
Indicative CAPEX ⁸ , USD	CAPEX is included in the landed costs of the hydrogen.

Each option has technical barriers with the choice of supply pathways dependent on Singapore's goals to meet its decarbonised targets. The analysis concluded that domestic blue hydrogen production provides the most cost-effective option to decarbonise hydrogen production while hydrogen imports are the least economic, as shown in Figure 11.1 below (blue line corresponds to the landed cost of imported hydrogen).

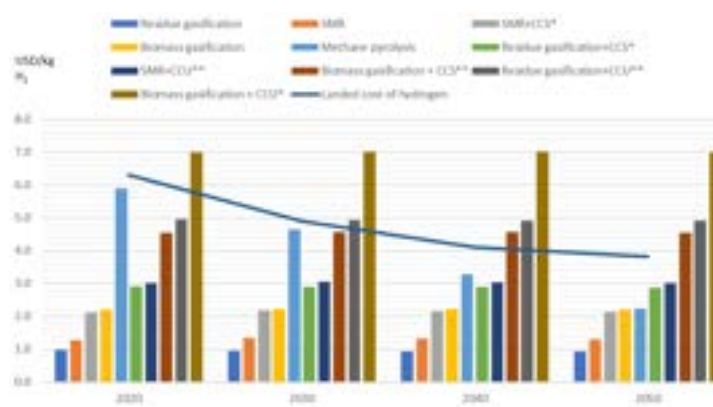


Figure 11.1 – Hydrogen Production Costs

Figure 11.1 shows that domestically produced blue hydrogen (Option 1) has the lowest production costs and could have high deployment potential if there is a viable solution to store the carbon. Biomass gasification (Option 2) has similar production costs to Option 1; however, it has large land requirements to handle and store biomass feedstock, in addition to the challenges of securing reliable biomass supply. Methane pyrolysis technology (Option 3) is still in the early stages of development. Some of its challenges include monetising carbon products and the need for further technological development to bring it to commercialisation. Hydrogen production cost via methane pyrolysis is expected to become competitive when compared to Options 1 and 2 by 2050. However, breakeven prices remain challenging throughout the outlook period as shown in Figure 7.3, Section 7.

Cost and land constraints would pose the greatest barriers for the replacement of current brown hydrogen feedstock with domestic low-carbon hydrogen.

Replacing merchants' brown hydrogen with imported green or blue hydrogen may have the lowest upfront capital cost for the sector (Option 4). This option would need smaller land requirement compared to domestic production⁸. However, projected high landed costs and low maturity of a large-scale hydrogen export supply chain are barriers to adoption (see Section 6).

⁶ Carbon emissions may be associated to the liberation of hydrogen from the carrier depending on the source of energy used. Please see Section 5 for more information.

⁷ Further analysis of the carriers' storage and CAPEX can be found in Section 5 and 13.

⁸ Hydrogen or carrier receiving facilities will require additional land footprint, however this is shared infrastructure for all of the sectors and does not impact the industrial and manufacturing sector footprint solely

Nevertheless, merchants operating in Singapore have corporate-level plans around decarbonisation and are investing globally in renewable hydrogen technologies and infrastructure. Therefore, merchants could replace a portion (or all) of their hydrogen production with imported low-carbon hydrogen.

Hydrogen as Fuel and Autoproducers

Hydrogen as Fuel

Main industrial fuel gas users include refineries, and petrochemical and chemical plants that burn fuel required by their manufacturing processes. Heat is obtained by burning fuel directly in furnaces or indirectly via steam obtained by burning fuel on factory boilers. In such facilities, primary fuel usage comes from crude light ends and internal process off gases. However, internal fuel gas production is generally not enough to satisfy total fuel gas requirements for furnaces, boilers and utilities. Therefore, natural gas is used to make up for the energy deficit.

Figure 11.2 shows historic and projected industrial natural gas consumption, assuming that energy efficiency improves by 0.01% per annum over the outlook period. It is also assumed that there will be a year-to-year fuel increment ranging between 2% to 1%, which will result in a 50% increase of total natural gas requirement compared to 2018 values.

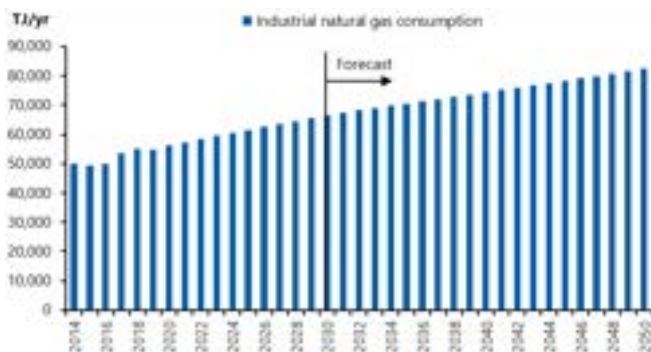


Figure 11.2 – Industrial Gas Consumption – Including Energy Efficiency Growth

Low-carbon hydrogen can be used to decarbonise heat in industrial processes, in particular, for high-grade (over 500°C) and medium-grade (200°C to 500°C) heat applications which are difficult to electrify.

If the fuel gas deficit is completely replaced by hydrogen, there are no key showstoppers from the technical viewpoint; however, replacement of burners to ultra-low NOx burners and upgrades in the metal thickness of flame-exposed parts might be required. Assessment on a case-by-case basis will be needed to determine whether a retrofit is needed to allow for higher hydrogen content in fuel gas.

Based on the discussion above, two options have been analysed to assess the changes required to incorporate hydrogen as a fuel on industrial facilities by partially or completely replacing natural gas supply with hydrogen:

- **Option 1:** considers blending 5vol% hydrogen to natural gas which is purchased as supplementary fuel. This ratio has been selected for alignment with the power sector.
- **Option 2:** assumes that all the supplemental natural gas purchased by industrial players is replaced with hydrogen.

The options above do not replace internal fuel gas; which for this study has been assumed as 80% of the total fuel blend.



Table 11.6 and Table 11.7 show the amount of hydrogen that would be required until 2050 as well as the carbon abatement for the two options.

Table 11.6 – Option 1 to Deploy Hydrogen for Industrial Fuel Gas Users (Furnaces and Boilers).

Option 1	UoM	2020	2030	2040	2050
5% Hydrogen + 95% natural gas fuel blend (vol)	mn m ³ /year	1,453	1,718	1,923	2,132
5% Hydrogen	mn m ³ /year	73	86	96	107
5% Hydrogen	kt/year	7	8	9	10
CO ₂ emissions abatement	mn t/year	0.05	0.05	0.06	0.07

Table 11.7 – Option 2 to Deploy Hydrogen for Industrial Fuel gas Users (Furnaces and Boilers)

Option 2	UoM	2020	2030	2040	2050
100% Hydrogen	mn m ³ /year	5,197	6,147	6,878	7,625
100% Hydrogen	kt/year	468	553	619	686
CO ₂ emissions abatement	mn t/year	3.3	3.9	4.3	4.8

Autoproducers

While a significant share of electricity requirement is fulfilled by the grid, the remaining requirement is realised by internal power generation. Internal power generation is achieved by steam-driven turbo-generators and by GTs (with associated equipment – e.g. CCGT, Co-Gen and Tri-Gen).

Steam-driven turbo-generators do not use natural gas as fuel and therefore are not covered in this section. Steam used for those turbines is either generated in the boilers (covered earlier in this section) or as by-product from other processes.

Although GTs can operate for a wide variety of fuels, including fuels with low, moderate, and high levels of hydrogen, they typically operate with natural gas. However, depending on facility design, some may need a gas blend which includes hydrogen.

Recently, due to the desire to reduce carbon emissions from traditional power generation assets, GT vendors are examining changes required to upgrade existing turbines to allow fuels with higher hydrogen content. The advantage of GT is the ability to be re-configured for operations using new fuels, including fuels with increased levels of hydrogen. Some existing vendors' GTs can process high volumes of hydrogen. HENG turbines are discussed in Section 9.

Natural gas demand for autoproducers is projected to remain constant for the 2020-2050 period, since there are no concrete plans for facility expansion exits. Table 11.8 shows estimated natural gas consumption for autoproducers over the 2020 to 2050 period.

Table 11.8 – Estimated Autoproducers Natural Gas Consumption

Description	UoM	2020-2050
NG consumption	TJ/year	48,060
	TJ/hour	5.4863
	MWH	1,524

Similar to the industrial fuel section of this report, two options have been analysed to assess the changes required to incorporate hydrogen as an industrial fuel:

- **Option 1** considers blending 5vol% hydrogen to natural gas; and
- **Option 2** assumes that all natural gas is replaced with hydrogen.

Table 11.9 and Table 11.10 show the amount of hydrogen that would be required until 2050 and the carbon abatement for the two options.

Table 11.9 – Option 1 to Deploy Hydrogen for Auto Producers

Option 1	UoM	Fuel Requirement
5% H ₂ +95% NG fuel blend (vol)	mn m ³ /year	1,241
5% Hydrogen	mn m ³ /year	62
5% Hydrogen	kt/year	5.6
CO ₂ emissions abatement	mn t/year	0.05

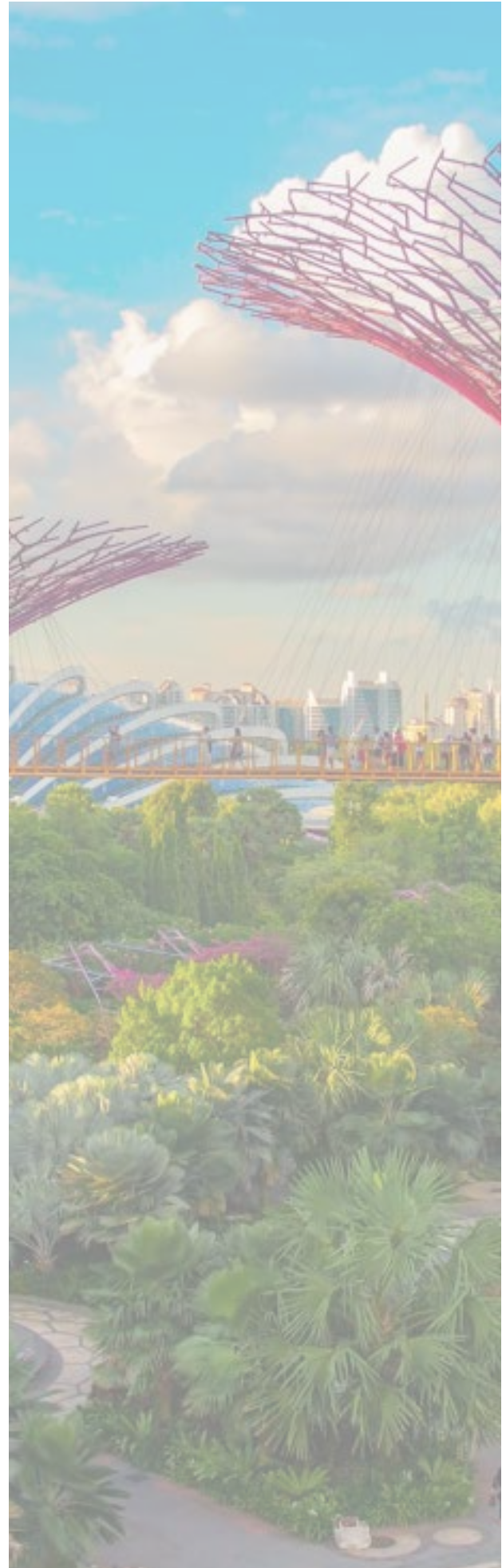
Table 11.10 – Option 2 to Deploy Hydrogen for Auto Producers

Option 2	UoM	H ₂ Requirement
100% Hydrogen	mn m ³ /year	3,784
100% Hydrogen	kt/year	339
CO ₂ emissions abatement	mn t/year	2.8

Hydrogen can be deployed in the industrial sector for decarbonisation. The analysis indicates that 5vol% blend of hydrogen (option 1) in the existing fuel blend can be implemented without equipment retrofitting for both heat and internal electricity generation. Considering power sector players and industrial fuel users are sharing natural gas infrastructure, hydrogen deployment in both sectors could be done simultaneously. Considering lead times, hydrogen receiving and blending infrastructure for a 5vol% hydrogen blend could be completed by 2030. See Section 13 for receiving infrastructure analysis.

If natural gas is replaced with 100% hydrogen (option 2), the need for burner replacement will have to be assessed on a case by case basis. Also future limits in NO_x emissions may require existing burners to be replaced with Ultra NO_x burners regardless of the hydrogen content in fuel gas. For autoproducers, retrofitting or replacement will be required for the GTs if natural gas is replaced with 100% hydrogen (option 2). The difference in CAPEX and OPEX between conventional natural gas turbines and 100% hydrogen turbines is assumed to be insignificant at the industrial scale.

Industrial fuel and autoproducers' breakeven prices remain challenging across the analysed period as shown in Figure 7.3, Section 7.



12

Marine and Ports

"As port operators seek to decarbonise, hydrogen is an attractive fuel with many potential port applications. As the world's leading bunker hub, Singapore is well positioned to leverage any changes to global bunkering fuel and also retain its strategic importance in the sector."



Singapore's maritime industry is a crucial part of its economy. Currently, there are over 130 international shipping groups and 5,000 maritime companies that contribute approximately 7% of Singapore's GDP and employ more than 170,000 personnel. Singapore is one of the busiest ports in the world and has been ranked as a top international maritime centre. Singapore is also the top bunkering hub with 130,000 vessels making port calls annually. In addition to its maritime capabilities, Singapore is also the world's third-largest petrochemical refiner and operates one of the most technically advanced shipbuilding and ship-repair facilities in the region.

As port operators seek to decarbonise the sector, hydrogen is an attractive fuel with many potential applications, from berthing to unloading and sorting within the port. There are currently many hydrogen-based bunkering fuels being studied in the maritime industry (e.g. liquid hydrogen, ammonia, methanol). For this study, the use of hydrogen fuel cells was considered to power harbour crafts, quay and yard cranes, as well as heavy-duty vehicles that move the containers within the port premises.

Harbour crafts are defined as vessels that ply the Singapore waters and include tugboats, bunker tankers and passenger ferries. Traditionally, these are all powered by diesel which emits a significant amount of carbon dioxide when burnt.

As the ports in Singapore are being consolidated at the Tuas port currently, it could be an opportunity for the ports to swap in hydrogen-fuelled equipment to complement the automation and decarbonisation plans for the new port.

Tugboats

As vessels approach the port, tugboats help to guide and manoeuvre the vessel to the designated berths. tugboats are essential to tow mega-vessels which have less manoeuvring capability through narrow channels. Tugboats typically operate near the shipyards and port terminals which are mainly located in the west of Singapore.

Given the operational profile of tugboats, the cost competitiveness of hydrogen powered tugboats with diesel tugboats gets better as the fuel cell technology improves, which brings down capital and fuel costs. Figure 12.1 illustrates that hydrogen-powered tugboats could achieve cost competitiveness with LNG and diesel tugboats in 2030.



Figure 12.1 – Breakeven Prices for Tugboats

[Note: Bespoke models, for both cost and demand estimation, were developed for the analysis. Hence the results might differ from estimates in the literature.]

As seen in Figure 12.2, electric tugboats have a head start over hydrogen fuel cell as there are variants of electric tugboats available in the market already while also facing the same upside with future technological improvements in battery. However, electric boats face issues with range as well as charging infrastructure. These aspects might impede their uptake.

LNG and diesel vessels are forecasted to be more economical to own and operate due to their relatively lower capital cost and the low cost of fuel, such as natural gas and diesel, in the near term. However, as the technology for fuel cells improve and the price of hydrogen falls with increasing uptake of hydrogen production across the world, hydrogen fuel cell tugboats could be cost competitive by 2030 (see Figure 12.2).

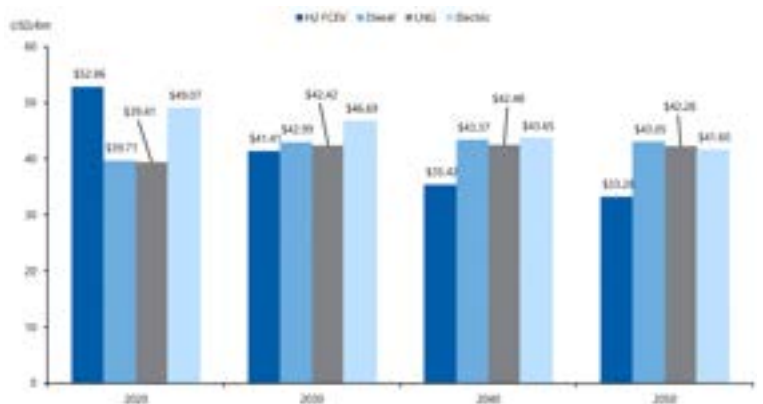


Figure 12.2 - LCOT of Tugboats by Fuel Type

Passenger Boats

Another essential harbour craft for port services are passenger boats/ferries, which ferry passengers across the sea to larger vessels.

As with the tugboats, the fuel cell powered boats can become competitive with diesel-fuelled ferries in the future as the fuel cell technology improves. Electric boats (with their higher efficiency) and diesel and LNG vessels (with low fuel costs) are still likely to be the cheaper option compared to fuel cell ferries in the near future. Figure 12.3 illustrates the breakeven prices for hydrogen vessels versus their LNG, electric and diesel equivalents.



Figure 12.3 - Breakeven Prices for Passenger Boats

[Note: Bespoke models, for both cost and demand estimation, were developed for the analysis. Hence the results might differ from estimates in the literature.]

As seen in Figure 12.4 and similarly to the LCOT of tugboats, the LCOT of hydrogen-fuelled passenger vessels is currently not competitive with the other fuel types due to the high fuel cost of hydrogen as well as the capital cost of fuel cell vessels. However, as the technology for fuel cells improves and the price of hydrogen falls with an increased uptake of hydrogen production across the world, hydrogen fuel cell tugboats could be cost competitive between 2035 and 2040.

Bunkering Tankers

Short-sea bunker tankers/bunker takers are larger than both the ferries and tugboats. These are used to refuel bigger vessels as they berth at the port of Singapore.

As with the tugboats and passenger ferries, the fuel cell powered boats can become competitive with electric vessels in the future as the fuel cell technology improves. However, compared to the other two variants, these are more fuel intensive as they are heavier and travel a longer distance. The LNG- and diesel-fuelled vessels are much cheaper than hydrogen-fuelled vessels as shown by the breakeven prices depicted in Figure 12.5.



Figure 12.5 - Breakeven Prices for Bunker Tankers

[Note: Bespoke models, for both cost and demand estimation, were developed for the analysis. Hence the results might differ from estimates in the literature.]

As seen in Figure 12.6 and similarly to the LCOT of tugboats and passenger ferries, the LCOT of hydrogen-fuelled bunker tankers is currently not competitive with the other fuel types due to the high fuel cost of hydrogen as well as capital cost of fuel cell vessels. Due to the higher fuel intensity of the bunker tankers (as a result of their size and operational needs), hydrogen fuel cell bunker takers are unlikely to become cost competitive with LNG-, diesel- or even ammonia-powered vessels over the outlook period.



Figure 12.4 - LCOT of Passenger Boats by Fuel Type

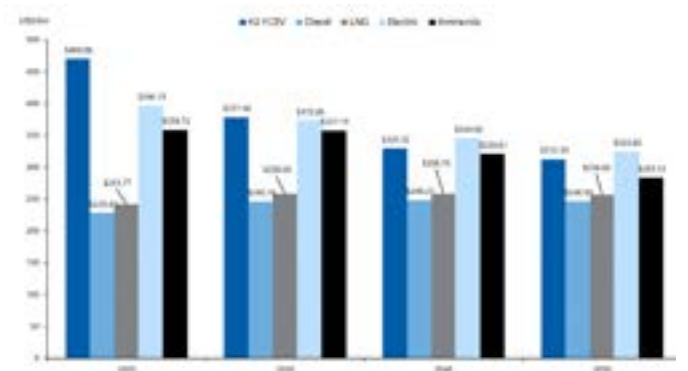


Figure 12.6 - LCOT of Bunker Tankers by Fuel Type

Cranes

Cranes are used in port operations to move containers from ships to land as well as to sort and redistribute them across the port. The cranes in the port of Singapore have gradually been switched to electric ones, with 186 automated yard cranes being deployed by PSA.

As the fuel cell technology develops, hydrogen-powered cranes can become cost competitive with their diesel variants. Electric cranes are more difficult to catch up to as they are further ahead in the technology curve and also much more efficient compared to diesel cranes. These trends can be seen in the hydrogen breakeven prices in Figure 12.7.

Table 12.1 details maritime and port equipment assessed and key assessment conclusions.

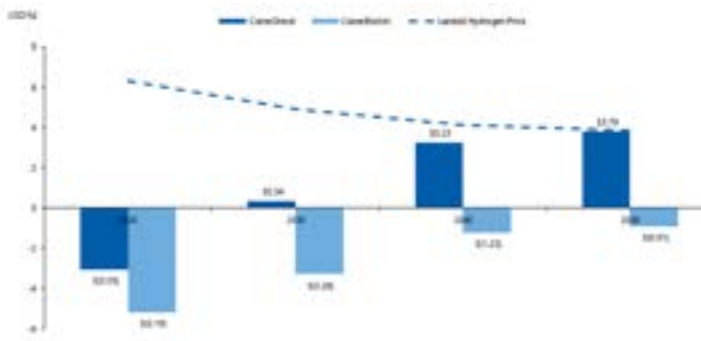


Figure 12.7 - Breakeven Prices for Cranes

Yard Trucks

Heavy-duty trucks used to transport containers within the premise of the port can also be targets of the decarbonisation efforts.

Hydrogen fuel cell trucks can also be deployed as a carbon-free option. The analysis of this sector is similar to the heavy-goods vehicles in the mobility sector, where the hydrogen fuel cell trucks improve across time and would become cost competitive with both diesel, electric and LNG trucks in the future, as seen in Figure 12.8.

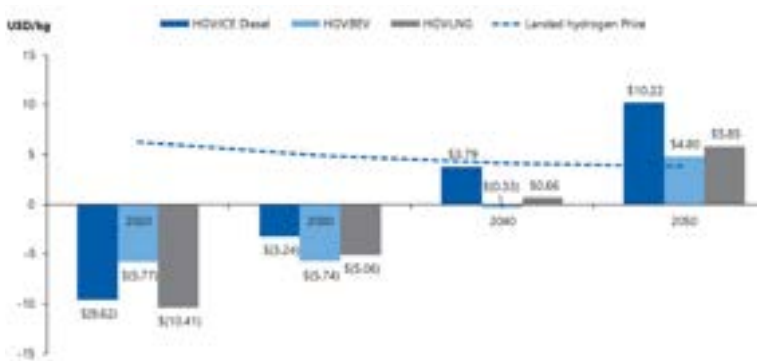


Figure 12.8 - Breakeven Prices for Yard Trucks (HGV) by Fuel Type

Table 12.1 – Maritime and Port Equipment Assessed and Key Assessment Conclusions

Maritime and Port Equipment	Description	Conclusion
 <p>Tugboats</p>	<p>As vessels approach the port, tugboats help to guide and manoeuvre the vessel to the designated berths. Tugboats are essential to tow mega-vessels which have less manoeuvring capability through narrow channels. There are approximately 370 tugboats across the various terminals in Singapore.</p>	<p>Given the operational profile of tugboats, the cost competitiveness of hydrogen-powered tugboats against diesel tugboats gets better as the fuel cell technology improves, which brings down capital and fuel costs. Hydrogen-powered tugboats could achieve cost competitiveness with LNG and diesel tugboats in 2030.</p>
 <p>Passenger Boats</p>	<p>Passenger boats/ferries ferry passengers across the sea to larger vessels. There are around 150 passenger boats working the Singaporean waters currently and this is likely to increase as the port expands. These vessels operate at a higher speed and have more variabilities in their work cycle.</p>	<p>As with the tugboats, the fuel cell powered boats can become competitive with diesel-fuelled ferries in 2045 as the fuel cell technology improves. Electric boats (with their higher efficiency) and diesel and LNG vessels (with low fuel costs) are still likely to be the cheaper option compared to fuel cell ferries in the near term.</p>
 <p>Bunker Tankers</p>	<p>Short-sea bunker tankers are larger than both ferries and tugboats. These are used to refuel bigger vessels as they berth at the Port of Singapore. There are around 250 bunker tankers in Singapore currently.</p>	<p>Fuel cell powered boats can become competitive with electric vessels in the future as the fuel cell technology improves. However, compared to the other two variants, these are more fuel intensive as they are heavier and travel a longer distance. Due to the higher fuel intensity of the bunker tankers (as a result of their size and operational needs), hydrogen fuel cell bunker tankers are unlikely to become cost competitive with LNG-, diesel- or even ammonia-powered vessels over the outlook period.</p>
 <p>Cranes</p>	<p>Cranes are used in port operations to move containers from ships to land as well as to sort and redistribute them across the port. The cranes in the Port of Singapore have gradually been switched to electric ones, with 186 automated yard cranes being deployed by PSA. This number has been forecasted to reach almost 1,000 when the new port is completed¹.</p>	<p>As the fuel cell technology develops, hydrogen-powered cranes can become cost competitive with their diesel variants in around 2035. However, the hydrogen technology does not become competitive with electric cranes due to the increased efficiency.</p>
 <p>Yard Trucks</p>	<p>Heavy-duty trucks used to transport containers within the premise of the port can also be targets of the decarbonisation efforts. PSA recently procured a total of 200 LNG trucks to be delivered in 2021 which would reduce the trucks' carbon emissions. Hydrogen fuel cell trucks can also be deployed as a carbon-free option. is completed³⁹.</p>	<p>The analysis of this sector is similar to the heavy-goods vehicles in the mobility sector, where the hydrogen fuel cell trucks improve across time and would become cost competitive with both diesel, electric and LNG trucks in 2040.</p>

¹ CNA Insider (2019). From working atop cranes to handling computers, a 'dinosaur' keeps up with change. <https://www.channelnewsasia.com/news/cnainsider/psa-yard-crane-operator-automation-ppc-retraining-tuas-port-11483118>.

In Table 12.1, an analysis of hydrogen economics as a fuel relative to the incumbent as well as alternative fuels was provided. In some cases (such as yard trucks), hydrogen emerges as viable over the long term; in others (such as bunker takers), it is not viable. Factors such as usage intensity fuel prices and cost structures impact hydrogen economics, ammonia and other fuels competing with the incumbent.

Aside from these factors that drive the economics of the transition, there are other considerations that operators of vessels and ports would have to consider when making the decision to migrate to alternative fuels. Some of these include:

- **Fuel availability:** In principle, green hydrogen can be produced via electrolysis where there is green electricity available. But there are questions the availability of economically priced green hydrogen and when sufficient off-take quantities would be available. This uncertainty impacts uptake.
- **Technological maturity:** Several aspects of the green hydrogen and green ammonia supply chain have not yet been developed. For instance, centralised ammonia cracking is expected to be viable only post-2030. This could impact hydrogen availability as a marine fuel if ammonia becomes the predominant carrier. Engines capable of running on ammonia are not yet a mature technology if it is used as a marine fuel. The availability of reliable technology to power vessels is crucial to operators.
- **Safety considerations (such as flammability and toxicity):** Flammability limits show vapour concentration ranges of certain chemicals, expressed in volume percentages, which a flammable mixture of airborne gas or vapour can be ignited at 25°C and atmospheric pressure. A wide range (such as for hydrogen) indicates a fuel that is flammable under several conditions, in the absence of additional safety measures, this indicates higher risk. The toxicity of a fuel like ammonia is a concern when deciding to switch.

Bunkering

The International Maritime Organisation (IMO) has committed to reducing greenhouse gas emissions from international shipping by at least 50% from 2008 levels. To achieve this, the IMO believes that efficiency gains alone are not enough. A transition to zero-carbon fuels, such as hydrogen-based bunkering fuel alternatives (liquid hydrogen, ammonia and methanol) and electricity from renewable energy resources is needed to meet the IMO's greenhouse gas (GHG) reduction targets.

A study² found that from now to 2030, fossil-based LNG and biodiesel from the 1st and the 2nd generation feedstocks are foreseen to be potential measures to reduce onboard GHG emissions by 5 - 20%. Long term, the study concludes that hydrogen will be a viable option to decarbonise the shipping industry.

Several other global ports have recognised the potential of hydrogen fuels for marine applications and have commenced trials. The list below shows the ports that stood out as world leaders. It is recommended that hydrogen developments for these ports be monitored for any major developments which indicate a large-scale transition towards hydrogen or alternative fuels:

- **Port of Rotterdam:** Found to have an extensive and detailed publicly available plan for a transition to a greener future, with hydrogen playing a key role in the transition. In addition, this port is also a global pioneer when it comes to LNG bunkering infrastructure development^{3 4}.
- **Port of Yokohama:** Largely driven by Japan's national drive for sustainability and development of a hydrogen economy, Yokohama Port was identified as a leading sustainable port. It has plans to trial a hydrogen powered "E5 tug" and implement various other HFC-powered vehicles in port operations^{5 6}. In addition, Japan plans to turn the port into an international LNG bunkering hub⁶.

² The Maritime Energy & Sustainable Development (MESD) Centre of Excellence, 2020, Alternative Fuels for International Shipping

³ Port of Rotterdam, "Carbon neutral in 3 steps," 2020. [Online]. Available: <https://www.portofrotterdam.com/en/doing-business/port-of-the-future/energy-transition/carbon-neutral>.

⁴ THE MARITIME EXECUTIVE, "LNG Bunkering Options Expand Globally," 02 12 2020. [Online]. Available: <https://www.maritime-executive.com/article/lng-bunkering-options-expand-globally>.

⁵ Toshiba, "Toshiba H2One™ Hydrogen Based Autonomous Energy Supply System Now Providing Power to the City of Yokohama's Port & Harbor Bureau," 21 04 2016. [Online]. Available: https://www.toshiba.co.jp/about/press/2016_04/pr2101.htm.

⁶ Ministry of Economy, Trade and Industry, "Basic Hydrogen Strategy (key points)," 2017. [Online]. Available: https://www.meti.go.jp/english/press/2017/pdf/1226_003a.pdf.

Barriers to Transition

Although hydrogen-based bunkering fuel alternatives (liquid hydrogen, ammonia and methanol) show promise for meeting IMO 2050 targets, each have significant technical issues and drawbacks that need to be overcome before large-scale adoption can occur. Alternative hydrogen-based fuels are yet to be proven as commercially viable due to the high cost of green hydrogen production. As a consequence, ports around the world are currently showing significant interest in LNG as an alternative fuel. The major barriers to the adoption of hydrogen-based bunkering fuels include:

- Government and international climate change policy with regards to GHG emissions.
- The economic viability of producing hydrogen from low carbon/renewable energy.
- The development of hydrogen infrastructure is slow and holding back widespread adoption.
- Hydrogen is almost entirely supplied from natural gas and coal today.
- Regulations currently limit the development of a clean hydrogen industry.

LNG Bunkering Transition Comparison

LNG has only been utilised as an alternative bunkering fuel relatively recently driven by a global push for emissions reductions, with the first LNG-powered ship being launched in 2015⁶. Since then, LNG has received a significant amount of attention in the marine industry as a cleaner alternative to petroleum-based fuels. There are now at least 120 LNG-powered ships in operation worldwide, with many ports around the world, including the ports of Rotterdam and Yokohama, heavily investing in LNG bunkering infrastructure⁷. It is expected that LNG use in bunkering will continue to grow over the coming decades with forecasts showing 41% of all marine fuel will be LNG by 2050⁸. Although industry will likely benefit from its experience in its transitioning to LNG fuels, there are several major differences between the technologies that need to be highlighted when making the transition to hydrogen-based fuels. The main identified differences were:

- Cryogenic storage requirements: conventional LNG cryogenic storage tanks cannot be used for liquid hydrogen due to the increased temperature demands of hydrogen (-253°C vs -163°C for LNG).

- Usability in combustion engines: neither ammonia or hydrogen can be used alone in internal combustion engines unlike LNG. While methanol can be used to power a combustion engine, it cannot currently be produced as a green energy alternative.
- Fuel systems: LNG fuel systems cannot be used for hydrogen without modification as the components would likely leak due to the significantly smaller molecular size of hydrogen when compared to methane (primary component of LNG)⁹.

Signposts to Monitor

Interest in hydrogen as an energy source is being driven by government emission reduction targets and a switch to greener fuels. Signposts to gauge progress towards hydrogen implementation at ports include:

- Monitoring world targets for emission reductions;
- Monitoring progress of hydrogen trials at other ports.

Furthermore, there are specific projects underway to stay up to date with, listed below, for the development and trial of decarbonised marine technologies:

- The Norwegian organisation, NCE Maritime Cleantech, plans to retrofit an offshore vessel with a 2MW ammonia fuel cell, allowing the vessel to operate solely on clean fuel for up to 3,000 hours annually. The project, which has received funding and is targeting completion by 2023, is claimed by the developers to be a world first¹⁰.
- Ammonia engine technology is being developed by Wärtsilä and MAN Energy Solutions (ME). Wärtsilä is conducting tests on both dual-fuel and spark-ignited gas engines. These will be followed by field tests in collaboration with ship owners from 2022, and potentially also with energy customers in the future¹¹.
- The Castor Initiative is one of the leading collaborative projects working to develop the world's first ammonia-fuelled tanker. The alliance of MISC Berhad, LR, Samsung Heavy Industries, and MAN Energy Solutions was launched in January 2020. With the addition of Yara International ASA and Maritime Port Authority of Singapore, the six-member alliance now have complete representation from all areas of the maritime ecosystem.

⁶ SHIP TECHNOLOGY, "LNG bunkering facilities around the world," 28 08 2018. Available: <https://www.ship-technology.com/features/lng-bunkering-facilities-around-the-world>.

⁷ THE MARITIME EXECUTIVE, "LNG Bunkering Options Expand Globally," 02 12 2020. Available: <https://www.maritime-executive.com/article/lng-bunkering-options-expand-globally>.

⁸ The MotorShip, "From LNG to hydrogen? Pitfalls and possibilities," 14 07 2018. Available: <https://www.motorship.com/news101/alternative-fuels/from-lng-to-hydrogen-the-pitfalls-and-the-possibilities>.

⁹ World Maritime News, "World's 1st Ammonia-Powered Fuel Cell to Be Installed on a Vessel," 23 01 2020. [Online]. Available: <https://www.offshore-energy.biz/worlds-1st-ammonia-powered-fuel-cell-to-be-installed-on-a-vessel/>.

¹⁰ World Maritime News, "World's 1st Ammonia-Powered Fuel Cell to Be Installed on a Vessel," 23 01 2020. Available: <https://www.offshore-energy.biz/worlds-1st-ammonia-powered-fuel-cell-to-be-installed-on-a-vessel/>.

¹¹ Wärtsilä advances future fuel capabilities with first ammonia tests. Available: <https://www.wartsila.com/media/news/25-03-2020-wartsila-advances-future-fuel-capabilities-with-first-ammonia-tests-2670619>.

13

Infrastructure Requirements

"Singapore has extensive energy storage and transmission, including some that could be repurposed for a hydrogen-based economy."



This study assesses infrastructure requirements for receiving, storing and transmitting hydrogen throughout Singapore, including the feasibility of using existing infrastructure for hydrogen blending and deployment as well as new facilities.

Table 13.1 details key conclusions for the re-use of existing infrastructure within Singapore.

Table 13.1 – Singapore Existing Infrastructure Assessment Key Conclusions

Existing Infrastructure	Key Conclusions
LNG Facility	LNG facilities cannot accept liquefied hydrogen and new infrastructure will be required to receive/unload, store and transmit hydrogen domestically. The existing LNG unloading/reloading arm and LNG storage tank could be repurposed for ammonia offloading and storage due to the specific gravity difference between ammonia and LNG. To confirm the suitability of the LNG unloading/reloading arm and storage tanks for ammonia service, an engineering study should be undertaken.
Salt Caverns	Salt caverns are the most appropriate storage solution for large-scale hydrogen storage. Singapore has geological storage under Jurong Island with five rock caverns and 8km of tunnels storing up to 1.5 million m ³ of crude oil, condensate, naphtha and gas oil ¹ . These storage caverns support Singapore's petrochemical industry, so it is unlikely they will be able to be converted for hydrogen storage.
Ammonia Storage	In Singapore, there is 10,000m ³ of ammonia storage capacity at the Banyan terminal. Depending on the import volumes of ammonia expected in Singapore intended for energy use, it is likely that investment at the Banyan terminal would be required to expand ammonia storage capacity.
LOHC Storage	Singapore's chemical storage capacity is currently being used for chemicals and oil products. Given its chemical and physical properties, the existing chemical storage capacity is suitable for LOHC. Minor adjustments such as tank cleaning or new lines installations may be required.

Key conclusions for the requirement for new infrastructure within Singapore are as below.

Fuel Stockpiling

Power in Singapore is mainly produced by a mixture of natural gas and oil-fired power plants as well as some waste-to-energy facilities. Existing natural gas fired turbines used for power generation also use diesel as back-up fuel in the case of natural gas feedstock unavailability. Three back-up fuel options have been considered for HENG/hydrogen CCGT; LNG, CNG and line packing.

The line packing option was considered to be unfeasible due to constraints in pipe fabrication and the length of pipeline required.

A CNG solution, storing natural gas at 240 barg, will require compression facilities to achieve and maintain

required storage pressure in addition to a heating system to preclude the use of exotic materials. Both a centralised solution and a distributed CNG storage approach are technically feasible. Noting Singapore's land distribution challenges, a significant footprint will be required whichever approach is taken. CNG comprises approximately three times that of existing diesel storage requirements. This land requirement is considered to be unfeasible within the context of Singapore as a land-constrained island.

An LNG solution to meet back-up fuel requirements offers synergies with the existing facilities already provided at the Singapore LNG Terminal, however it is noted that there will be significant capital expenditure incurred due to the number of additional storage tanks required. If existing tanks can be utilised, CAPEX will be USD 1.6 billion for eight additional tanks. If existing infrastructure cannot be utilised, CAPEX will be USD 2.2 billion for eleven additional tanks.

¹ Geostock website "Our References - Jurong Rock Cavern Liquid Hydrocarbon Storage, Singapore" [<https://www.entrepose.com/en/reference/jurong-rock-cavern-liquid-hydrocarbon-storage/>]

New Infrastructure Requirements

The CAPEX of a new hydrogen receiving and regasification terminal is estimated assuming a hydrogen requirement of 9 MTPA and two jetties. (This hydrogen demand is based on the analysis of the downstream sectors and assumes all sectors transition fully to hydrogen). Two cases were considered, liquefied hydrogen and ammonia. For the ammonia facilities, two cases were assessed: greenfield ammonia receiving facilities as well as utilising existing LNG off-loading arms, jetty and storage tanks with four additional tanks and additional downstream equipment to transport ammonia.

- Liquefied Hydrogen CAPEX: USD 3.1 billion
- Ammonia Option 1 CAPEX: USD 1.8 billion
- Ammonia Option 2 CAPEX: USD 503 million

A typical engineering, procurement and construction (EPC) schedule for hydrogen receiving terminals has been developed. The schedule indicates minimum durations, with a five-year duration period from final investment decision to handover. Since hydrogen receiving and regasification facilities will need ten tanks by 2050 to meet storage requirements, construction will have to be phased due to limitations with materials logistics, laydown areas and workforce size. Using 2050 as a completion date for the tenth tank, and a standard building time of approximately 42 months for two tanks, it is recommended that the tanks are built in five phases, two tanks at a time, starting in 2033. This phasing of investment is reflected in the deployment pathways.

Hydrogen Transmission

Singapore has two natural gas transmission networks which transport gas to all power generation and industrial gas users across Singapore. It has four injection points from the Singapore Liquefied Natural Gas (SLNG) terminal, Indonesia as well as Malaysia with two operating pressures, 40 barg and 28 barg. Both networks have physical access to SLNG which allows Singapore to maximise its energy security to provide gas to all users in the event of a gas supply shortage or disruption.

It may be possible to explore the blending of hydrogen into gas transmission networks at a system level to provide a reduction in emissions to all end users and also capitalise on Singapore's existing infrastructure. Since existing pipelines have a single-phase gas line with turbulent flows, the hydrogen can be injected at any

single point and will not require downstream injection points (needed for the hydrogen-natural gas mixture to become homogeneous) to be piped over long distances. From experience, KBR recommend around ten pipeline diameters (around 7m for a 28" pipeline or 10.2m for a 40" pipeline) with an inline mixer or quill to ensure homogenous blending. As the existing network currently has four injection points and two operating pressures in the network, it is recommended that hydrogen be injected at each point where there is change in pressure. For example, one injection point in the 28 barg network and one injection point in the 40 barg network. Hydrogen should be injected at the same pressure as the gas at the injection point.

The maximum hydrogen blend that the gas transmission network can handle would require a deeper analysis to ascertain (e.g. via computational fluid dynamics simulation of the network). It would need to consider multiple factors including the limit before embrittlement issues in pipeline material would be prevalent, gas specification requirements of end-users (in terms of energy flowrate and delivered pressure), and the hydraulic limit of gas flow. A preliminary analysis of the allowable blend levels based on the hydraulic limit (i.e. acoustic velocity threshold of 20m/s) indicates that it could be increased to more than 5vol% (the proposed blend level for the gas network). However, this has not taken other determining factors such as embrittlement into consideration.

To provide hydrogen to end users for plant level blending or 100% hydrogen usage, a dedicated pure hydrogen gas network will be required. Constructing a new hydrogen pipeline infrastructure in Singapore would be a large project implemented in phases over several years.

Options for hydrogen transmission via pipeline in Singapore are detailed in Table 13.2.



Table 13.2 – Options for Hydrogen Transmission via Pipeline in Singapore

Option	Capacity (ktpa)	Operating Pressure barg	Pipeline Size / Configuration	CAPEX (USD)	Risks / Implications
Dedicated Network for 30vol% hydrogen	461	40	1 x 22" (97 km)	74.6 million	This pipeline is used as an intermediate step towards full decarbonisation of the power generation sector. If the sector moves to 100% hydrogen, the pipeline will be undersized for this capacity and a new pipeline will be required. Therefore the 22" network is at risk of becoming a stranded asset.
100% Hydrogen Network	6114	40	3 x 46" (291 km)	-	This pipeline diameter is larger than Singapore's current natural gas network (maximum diameter of 28") and it is not technically feasible to install pipelines of this diameter due to space constraints within Singapore.
100% Hydrogen Network	6114	100	3 x 30" (291 km)	364 million	This option is potentially more technically feasible than the 40 barg case, however, still exceeds the 28" diameter.

There are several significant issues/disadvantages of increasing the pipeline pressure to 100 barg which need to be considered:

- **Safety distances:** Safety distances between pipelines will increase which will impact the feasibility of laying three pipelines and limit the corridors that can be used.
- **Power requirements:** Pressurising hydrogen to 100 barg requires more energy than pressurisation to 40 barg and will impact the footprint and energy required at receiving terminals.

Hydrogen Safety

Table 13.3 summarises key safety issues pertaining to hydrogen compared to that of natural gas. In general, hydrogen poses significantly more safety challenges than natural gas. This means that hydrogen-related infrastructure is likely to be subjected to increased safety measures, which would likely lead to higher deployment costs. Although hydrogen is already deployed extensively in industrial applications with associated safety protocols and safety procedures, the safety aspects of hydrogen are more stringent and complex compared to natural gas, particularly around safety testing. Large scale hydrogen usage will require significant investment in understanding the behaviour of and therefore safety requirements for hydrogen.



Table 13.3 – Hydrogen Safety Considerations

Hydrogen Safety Risk	Natural Gas Risk	Risk Increase or Decrease
Hydrogen has a wider flammability range than other hydrocarbons; the flammability range for hydrogen is between 4% and 75% by volume in air.	The flammability range of methane is between 5% and 15% by volume in air.	Increase to the risk of flammability in air.
Hydrogen is highly reactive and poses an explosion hazard in both confined and unconfined regions.	A release of natural gas results in an explosion only in confined or congested environments.	Increase in the risk of explosion.
If there is a delayed ignition, there is potential for hydrogen to detonate with explosion overpressures > 10 barg.	Methane does not detonate under general process plant conditions and only has explosion overpressures < 1 barg.	Increase in risk to significant loss of life and property.
Hydrogen is extremely flammable and has potential to spontaneously ignite or ignite by static discharge or friction at a relatively low velocity. The minimum ignition energy for ignition of hydrogen (0.02 MJ).	Methane minimum ignition energy is 0.2 MJ.	Increase in the risk of leaked hydrogen finding an ignition source. Increase in the number of scenarios that could cause an ignition source.
Hydrogen burns with an almost invisible flame with low radiant heat, furthermore hydrogen cannot be odourised with mercaptans. This makes ignitions hard to detect with the naked eye.	Methane burns with a blue flame and can be odourised for leak detection.	Increase in the risk of hydrogen leak and ignition going undetected.
Hydrogen is the lightest gas and therefore has high diffusability (i.e. hydrogen can pass through thin membrane materials).	Methane is a larger molecule and is therefore less likely to diffuse through membrane materials.	Increase risk of hydrogen leak and special membrane materials required for construction.
Mercaptans cannot currently be employed with hydrogen as their Sulphur atoms bind irreversibly to the catalyst in the fuel cell membrane and rapidly halt its operation.	Mercaptans and thiophanes may be used to stench natural gas and liquefied petroleum gas (LPG), thereby greatly increasing the likelihood of early leak detection.	Increase risk of leak detection if a suitable odourisation chemical is not found for hydrogen.

A number of design and risk analysis/management measures to enable the safe use of hydrogen are listed below:

- Adequate separation of occupied buildings from hydrogen handling facilities. Due to the properties of hydrogen and higher operating pressures, it is likely that calculated safety distances will be larger compared to other fuels;
- Awareness of potential ignition sources;
- Implementation of detection and control systems;
- Measures to prevent hydrogen accumulation through adequate ventilation;
- Limit plant/site congestion;
- Hazard and risk analysis to identify hazards, assess consequences from potential fires/explosions and calculate risks associated with hydrogen infrastructure. The analysis should include assessment of:
 - » Fire events – extent/duration of jet fires and extent of flammable gas dispersion clouds to assess the impact on infrastructure and personnel located both outdoors and indoors; and
 - » Explosions – extent of explosion overpressures to assess impact on infrastructure and personnel located both outdoors and indoors.

14

Southeast Asia Demand

"The IEA has identified Singapore as one of the nations which could act as a regional hydrogen storage hub for strategic stocks due to its port infrastructure, proximity, and storage capacities."



Hydrogen could potentially be stored in Singapore to act as a buffer if supply disruptions occur. Although Singapore has a relatively small economy, it can work with other southeast Asian nations to create synergies and increase regional hydrogen demand, thus increasing scale and reducing costs. To determine the potential impact that southeast Asian hydrogen demand could have on Singapore's hydrogen strategy, an assessment has been undertaken. This includes the following nations:

- Indonesia;
- Malaysia;
- Vietnam;
- Thailand;
- The Philippines;
- Brunei;
- Myanmar;
- Cambodia; and
- Laos.

Analysis of these nations found that there are several hydrogen demand scaling constraints:

- First, it is a novel technology, consequently it requires substantial government direction to shape its role in the economy. The potential for hydrogen usage in southeast Asia, has to date, received scant attention from the various governments' policy makers¹.
- Considerable upfront CAPEX needed to establish an efficient supply chain is also an issue. Some countries in the region with the biggest potential, such as Indonesia, would potentially face significant infrastructure costs. Until the disparity is reduced southeast Asian countries, most are still looking to raise living standards would see little reason to divert scarce capital towards developing a hydrogen-based economy².
- The third factor includes the price/cost disadvantages of hydrogen and its needed technology.

Despite these challenges, there is potential for Singapore to catalyse hydrogen development in the region. This could include framing hydrogen as a means of monetising stranded assets, such as renewables too expensive to compete with subsidised fossil fuel powered generation technologies or fossil fuel resources like coal that are finding fewer off-takers. For instance, Singapore could try to form a partnership with Sarawak, where

the government appears willing to develop production capability, as well as demonstrating the economic viability and benefits of hydrogen exports. A demonstration of the economic benefits that would accrue from hydrogen production and export might help Southeast Asian countries better understand opportunity to maximise their resource bases. Figure 14.1 illustrates potential hydrogen demand in the region excluding Singapore, in 2030, 2040 and 2050. For Singapore, the power sector offers the largest potential for hydrogen uptake in terms of aggregate volumes. However, unlike Singapore, the other nations do have renewable potential that could be exploited. This might reduce the propensity to move towards hydrogen in power generation.

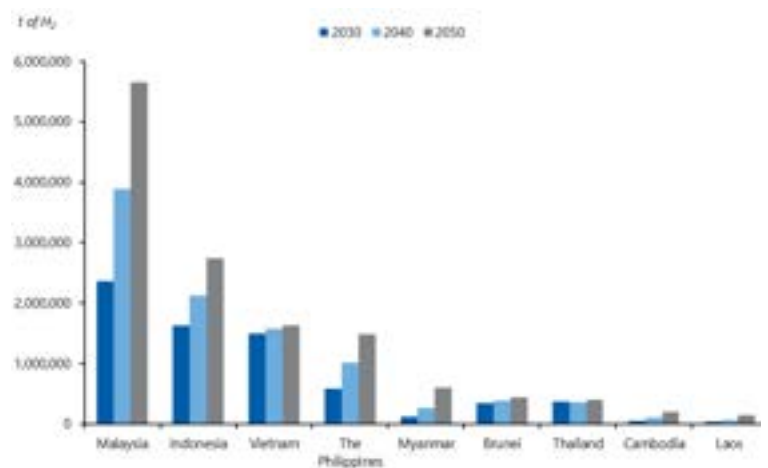


Figure 14.1 - Scenario for Hydrogen Demand Potential in Southeast Asia

¹ This could change going forward as hydrogen gets operationalised in Europe, North America and the Far East.

² This could change were domestic resources be used to produce hydrogen.

Figure 14.2 illustrates a scenario for potential hydrogen demand in the region (excluding Singapore) from power generation, industrial, non-industrial and transportation sectors. In this scenario, regional demand reaches 13. In all the countries considered in southeast Asia, countries already have the ability to produce hydrogen from domestic resources, including either fossil fuel, biomass or renewable resources. Therefore, some of their hydrogen needs can be met domestically without turning to imports. Using the assumption that 10% of southeast Asian demand would be attained from the seaborne market via Singapore as a trading hub, would increase Singapore's hydrogen demand by 1.3 million tonnes by 2050.

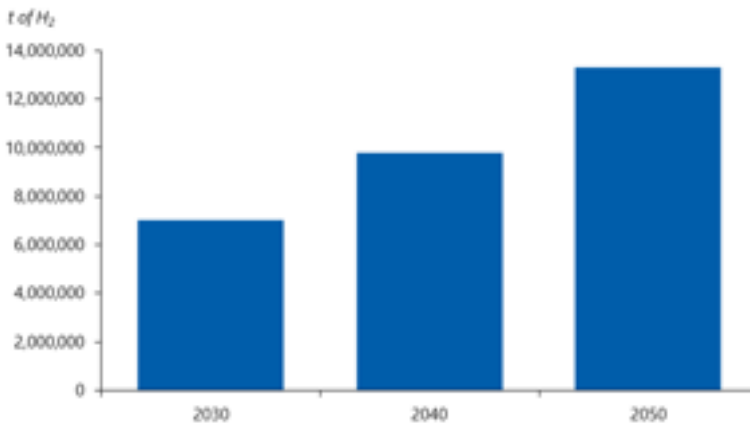
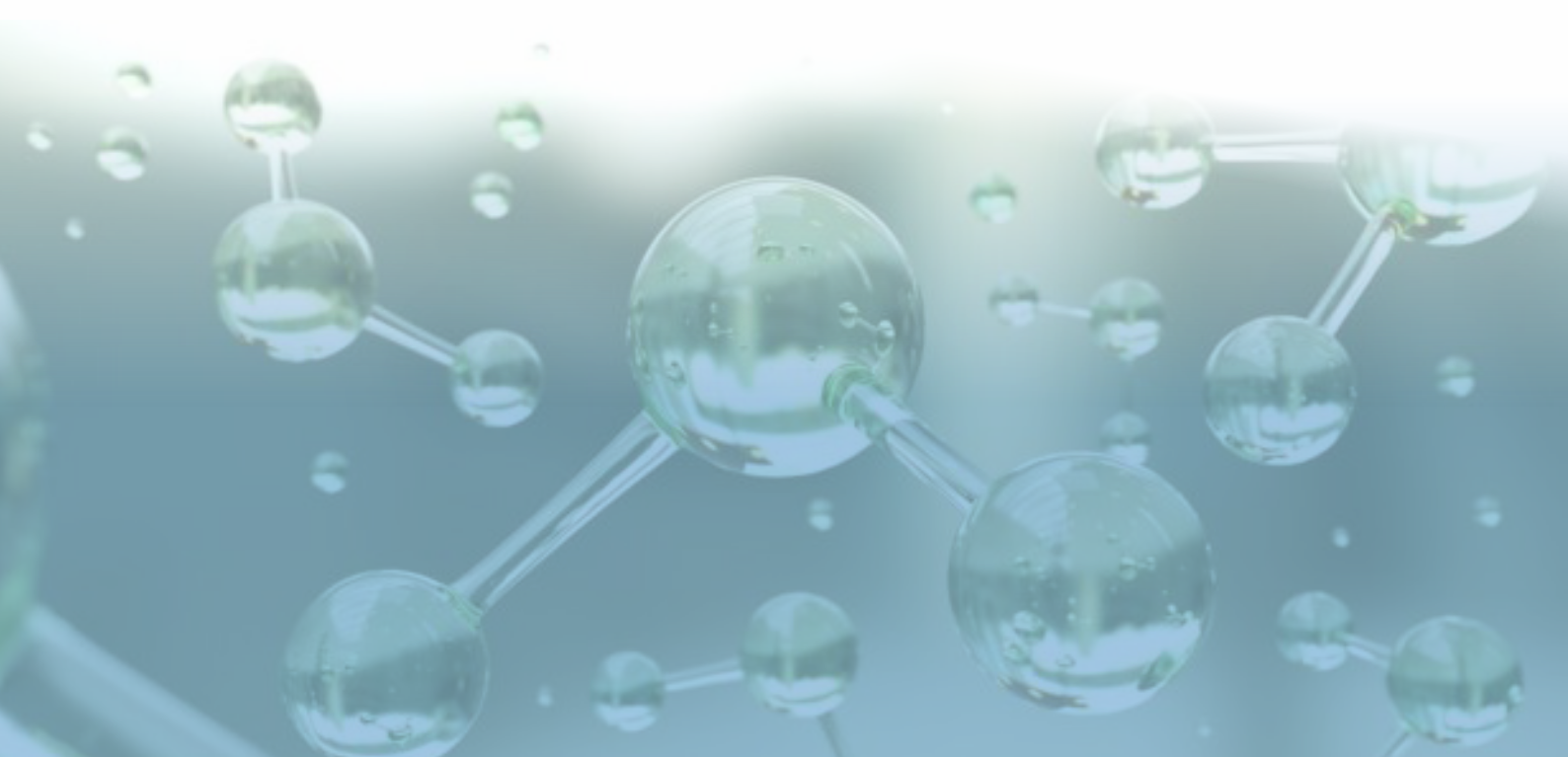


Figure 14.2 - Aggregate Hydrogen Demand in ASEAN (excluding Singapore)



15

Deployment Pathways

"Deployment pathways are intended to depict future hypothetical scenarios where hydrogen is imported into Singapore and adopted as a decarbonisation enabler in downstream applications for the 2020 to 2050 period."



Deployment pathways have been developed as a result of the technical and economic assessment undertaken throughout this report for each of the downstream sectors. The analysis includes the assessment of the current and forecast future demand in the downstream sectors for each deployment pathway against potential import sources for hydrogen supply.

The deployment pathways developed for this study are as follows:

- **Low Hydrogen Deployment:** Considers downstream hydrogen adoption when carbon abatement cost is economical. In this context, economical is defined as hydrogen deployment being lower in cost than, or competitive against, incumbent and alternative decarbonisation pathways or technologies.
- **Medium Hydrogen Deployment:** Considers downstream hydrogen adoption and applications in which carbon abatement cost is less than USD 250/tCO₂.
- **High Hydrogen Deployment:** Considers downstream hydrogen adoption when carbon abatement cost is less than USD 600/tCO₂.

Deployment pathways propose a timeline and phasing in of likely supply chains, technological development, areas of RD&D required, and policy and regulatory requirements necessary to achieve hydrogen deployment ambitions.



Pathway-neutral Enablers

Pathway-neutral enablers are considered 'no-regrets actions' that can be taken to initiate a potential hydrogen adoption landscape in Singapore before a definite deployment plan is considered and prepared. In other words, pathway-neutral enablers can pave the road for a future hydrogen deployment strategy in Singapore. Pathway-neutral enablers include (but are not limited to) actions that can be taken by Singapore to capitalise on low hanging fruit, transition to hydrogen in economically viable sectors or identify RD&D areas that can contribute technological solutions to the market. Pathway-neutral enablers also include regional and international cooperation with neighbouring countries and potential export source nations, as well as dialogue with domestic downstream sectors to understand the impacts of hydrogen adoption and possibilities. The overarching and individual sector-specific pathway-neutral enablers are listed in Table 15.1.

Table 15.1 - Pathway-neutral Enablers and Deployment Timeline

<p style="text-align: center;">Overarching</p> <p>Publicly publish a decarbonisation roadmap outlining clear focus areas and sectors for hydrogen deployment.</p> <p>Collaborate in the development of hydrogen regulations and standards.</p> <p>Prepare and conduct a public awareness campaign for hydrogen.</p> <p>Establish a collaborative approach, through RD&D collaboration and MOUs, with the exporting nations or projects for scaling, and secure future off-take agreements.</p> <p>Actively engage with peer nations committed to the establishment of a hydrogen economy.</p> <p>Support change management programs and development of vocational training in sectors where hydrogen deployment is expected to be economically favoured in the future.</p> <p>Engage in conversations with other South East Asian nations to form regional hydrogen strategies and initiate activities to create a framework for hydrogen certification / guarantee of origin (GO). Given the importance of clean hydrogen in enabling decarbonisation across the energy and industrial sectors, a GO scheme could be considered to properly verify and reward clean hydrogen production. This scheme would apply equally to all forms of hydrogen production and the threshold for what is considered 'clean' could be raised as the industry continues to mature.</p> <p>Establish a government hydrogen taskforce to monitor global developments and signposts in the hydrogen sector.</p>	<p style="text-align: center;"> Industrial and Manufacturing</p> <p>Establish a dialogue with industrial players to discuss potential future transition to hydrogen as fuel.</p> <p>Conduct detailed feasibility / engineering studies in the industrial sector related to low-carbon hydrogen adoption in the sector. Areas of study (per facility) include economic and operating impact of hydrogen deployment, maximum hydrogen intake in GTs and burners, safety impact, required GTs revamps (depending on level of adoption), transition costs and others as necessary.</p> <p>Develop a consortium of industry stakeholders to understand the needs of the industry and appropriate decarbonisation pathways and to discuss potential future adoption of green or low-carbon hydrogen as feedstock. This will also help to establish which taxes / incentives are most appropriate for the Singapore industrial sector. Stakeholders include hydrogen merchants, oil refining and petrochemical companies, chemical storage providers, industrial natural gas as fuel consumers (including auto producers), and others as necessary.</p> <p>Engage with the hydrogen merchants to understand their plans to shift operations to import low-carbon hydrogen into Singapore and to understand their corporate strategy with regards to low-carbon hydrogen production and future export capabilities.</p>	<p style="text-align: center;"> Maritime and Ports</p> <p>Develop a transition plan for yard trucks to transition to hydrogen as part of Tuas Port expansion phase 2.</p>
<p style="text-align: center;"> Mobility</p> <p>Conduct a feasibility study for the adoption of FCEV buses and HGVs.</p> <p>Develop transitional strategies for FCEV with deployment potential.</p>	<p style="text-align: center;"> Non-Industrial Gas</p> <p>Pilot hydrogen blending from imported hydrogen to understand operational fluctuations and test / demonstrate the supply chain.</p> <p style="text-align: center;">Infrastructure</p> <p>Engage with chemical storage stakeholders to attain information over long-term chemical storage options for ammonia, liquefied hydrogen and LOHC.</p> <p>Engage with chemical storage stakeholders to discuss potential expansion of existing ammonia and chemical storage facilities.</p> <p>Undertake engineering studies to assess:</p> <ul style="list-style-type: none"> ■ The suitability of a gas distribution network for hydrogen blending and import facilities. ■ The feasibility of all end-users on the natural gas network to accept 5vol% hydrogen blend. ■ The feasibility, configuration and layout of a new hydrogen transmission network for 100% hydrogen. 	<p style="text-align: center;"> Power Generation</p> <p>Demonstrate blending of hydrogen in existing CCGTs in Singapore to develop knowledge in hydrogen safety, handling and O&M, and to train operators.</p> <p>Pilot 100% hydrogen turbines to develop knowledge in hydrogen safety, handling and O&M, and to train operators.</p>

Hydrogen Availability

Hydrogen production potential of the import sources examined, based on the analysis from Section 6 across the forecast period, is depicted in Figure 15.1. These quantities are derived from interviews with relevant project stakeholders and encompass projects with the most certainty on volumes that could be exported to Singapore, therefore excluding New Zealand, Oman and Sarawak. Corresponding export volumes from these nations can be included after there is more certainty around these projects. This does not represent global supply potential but rather the supply potential from key projects/sources analysed in this particular study, based on currently available information. As this is a nascent and dynamic industry, there will be other potential projects and developments in the future, including planned project scale-ups, which could increase global hydrogen availability.

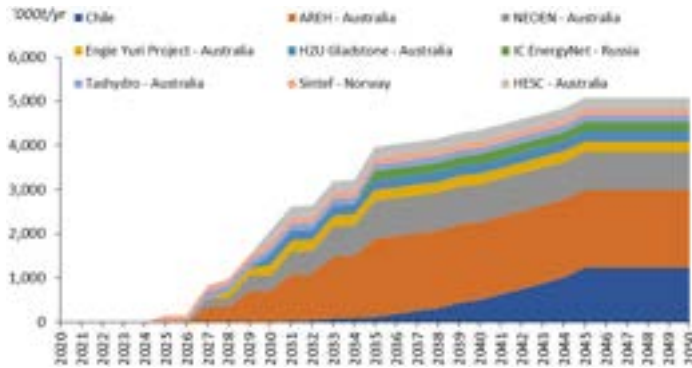


Figure 15.1 – Potential Hydrogen Supply from Import Projects that were Considered to have a Higher Likelihood of Producing Hydrogen for Export

Figure 15.2 illustrates potential import sources with Australia being the largest potential hydrogen exporter from the sources analysed. This is partly due to the country’s significant wind and solar resources (which is crucial to the economic production of green hydrogen via electrolysis), coupled with Australian policymaker’s support for the development of hydrogen production facilities for both domestic use as well as for exports.



Figure 15.2 – Potential Import Sources by Country

Not all of the production potential from these sources will be available for export, as portions of hydrogen production will be consumed domestically at source. Moreover, some of these exports have agreed off-take agreements to first movers like Japan and Korea. Hence, available export potential to Singapore will be a fraction of the export potential for each project.

Low Deployment Pathway

Figure 15.3 shows the level of hydrogen adoption in sectors where hydrogen demonstrates an economical cost of CO₂ abatement or where hydrogen technologies are competitive over the period assessed for the study. This deployment pathway only considers hydrogen adoption in the mobility sector for HGVs and the maritime sector for tugboats and passenger boats.



Figure 15.3 – Low Deployment Pathway

Figure 15.3 illustrates the hydrogen demand trajectory on an annual basis for low hydrogen deployment pathway. By 2050, the aggregate annual hydrogen demand from the two sectors is expected to reach 461 ktpa. This demand is around 9% of the hydrogen produced by the nine potential export sources to Singapore (see Figure 15.1).

Figure 15.9 illustrates hydrogen demand trajectory on an annual basis for medium hydrogen deployment pathway. Similar to the low hydrogen deployment pathway described above, the demand for hydrogen is largely driven by the maritime sector.

By 2050, aggregate annual hydrogen demand across all sectors is expected to reach 931 ktpa, around 18% of the potential exporters to Singapore.

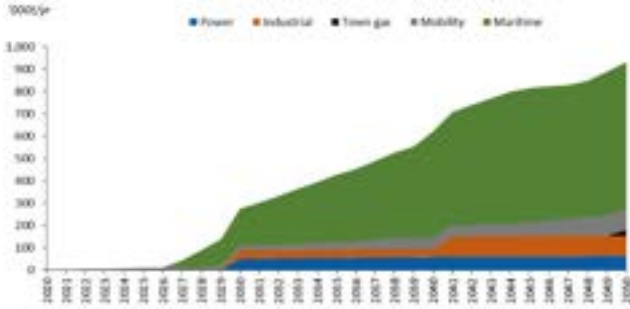


Figure 15.9 - Hydrogen Demand – Medium Hydrogen Deployment Pathway¹

Figure 15.10 illustrates carbon abatement in the medium hydrogen deployment pathway relative to the business-as-usual case. By 2050, total carbon abatement is expected to reach 10.4 Mt of CO₂ per year. It is largely driven by the marine sector as tugboats and passenger boats transition to hydrogen.

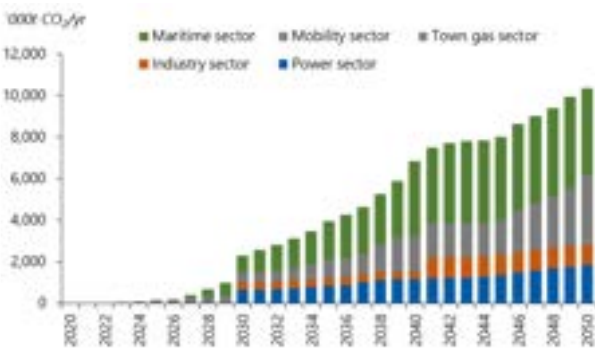


Figure 15.10 – Carbon Abatement – Medium Hydrogen Deployment Pathway

Figure 15.11 and Figure 15.12 illustrate the MAC curves in 2030 and 2050 for the medium deployment pathway.

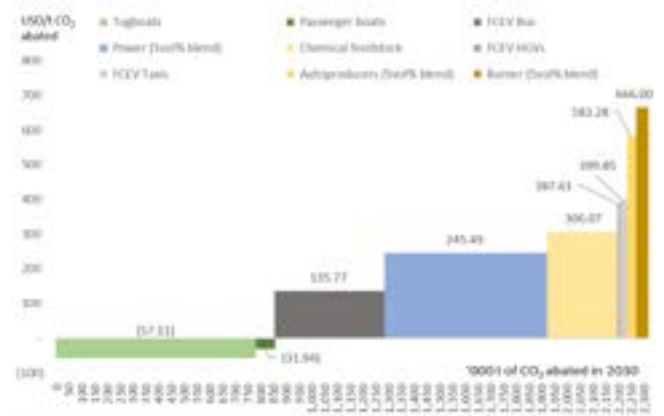


Figure 15.11 - MAC Curve – Medium Hydrogen Deployment Pathway (2030)



Figure 15.12 - MAC Curve – Medium Hydrogen Deployment Pathway (2050)

¹ It should be noted that in order to transition the sectors to hydrogen as per the adoption rates as required by this pathway, the uptake of hydrogen would already have had to have begun in 2024 led by the mobility sector.

High Deployment Pathway

Figure 15.13 shows the level of hydrogen adoption for the high hydrogen deployment pathway. A full description of hydrogen demand, carbon abatement potential, marginal abatement cost and other related aspects are explained in more detail in this section.



Figure 15.13 – High Hydrogen Deployment Pathway²

Hydrogen uptake for all sectors is depicted in Figure 15.14. The power sector is projected to replace retiring natural gas CCGTs with 100% hydrogen CCGTs from 2040 onwards. By 2050 around 63% of CCGTs would be transitioned creating significant hydrogen demand when compared to low and medium deployment pathways. In 2050, aggregate annual hydrogen demand from all sectors reaches 3,804 ktpa of hydrogen, equal to approximately 75% of the hydrogen export volumes.

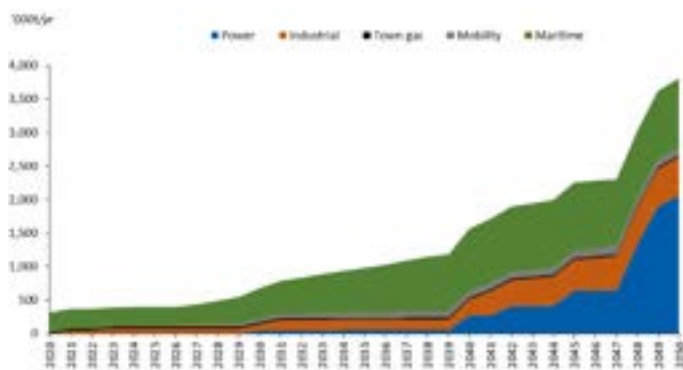


Figure 15.14 - Hydrogen Demand – High Hydrogen Deployment Pathway

Figure 15.15 illustrates carbon abatement in the high hydrogen deployment pathway relative to a business-as-usual case. Abatement increases up to 2040 is largely driven, as mentioned, by the marine sector as cargo vessels, tugboats and passenger boats transition to hydrogen. Post 2040, carbon abatement is projected to increase sharply in the power generation sector as natural-gas CCGTs are phased-out and replaced with 100% hydrogen CCGTs. Industrial fuel consumers will follow the power sector adoption rate mainly for logistical purposes (shared infrastructure). In 2050, carbon abatement stands at 24.5 Mt of CO₂ in the maritime sector is approximately ten times higher than the HGVs FCEV abatement.

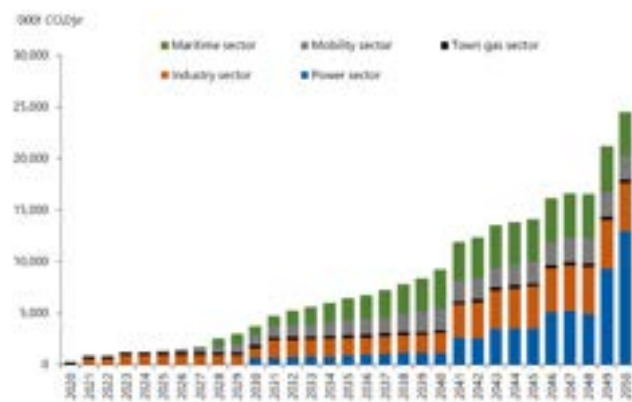


Figure 15.15 - Carbon Abatement – High Hydrogen Deployment Pathway³



² Figure 15.13 is intended to illustrate the target hydrogen adoption over the outlook period per sector. Since the NG GTs have a life span of 25 years, the adoption of hydrogen in the power sector will depend on the decommissioning of existing GTs and the installation of 100% hydrogen turbines. It is estimated that by 2050 only 63% of the GTs would have transitioned to hydrogen even though the figure shows a 100% adoption as target.

³ Given that the transition to hydrogen begins in 2020, there is a symmetric carbon abatement observed.

Figure 15.16 and Figure 15.17 below illustrate the MAC curves in 2030 and 2050 for the high deployment pathway.

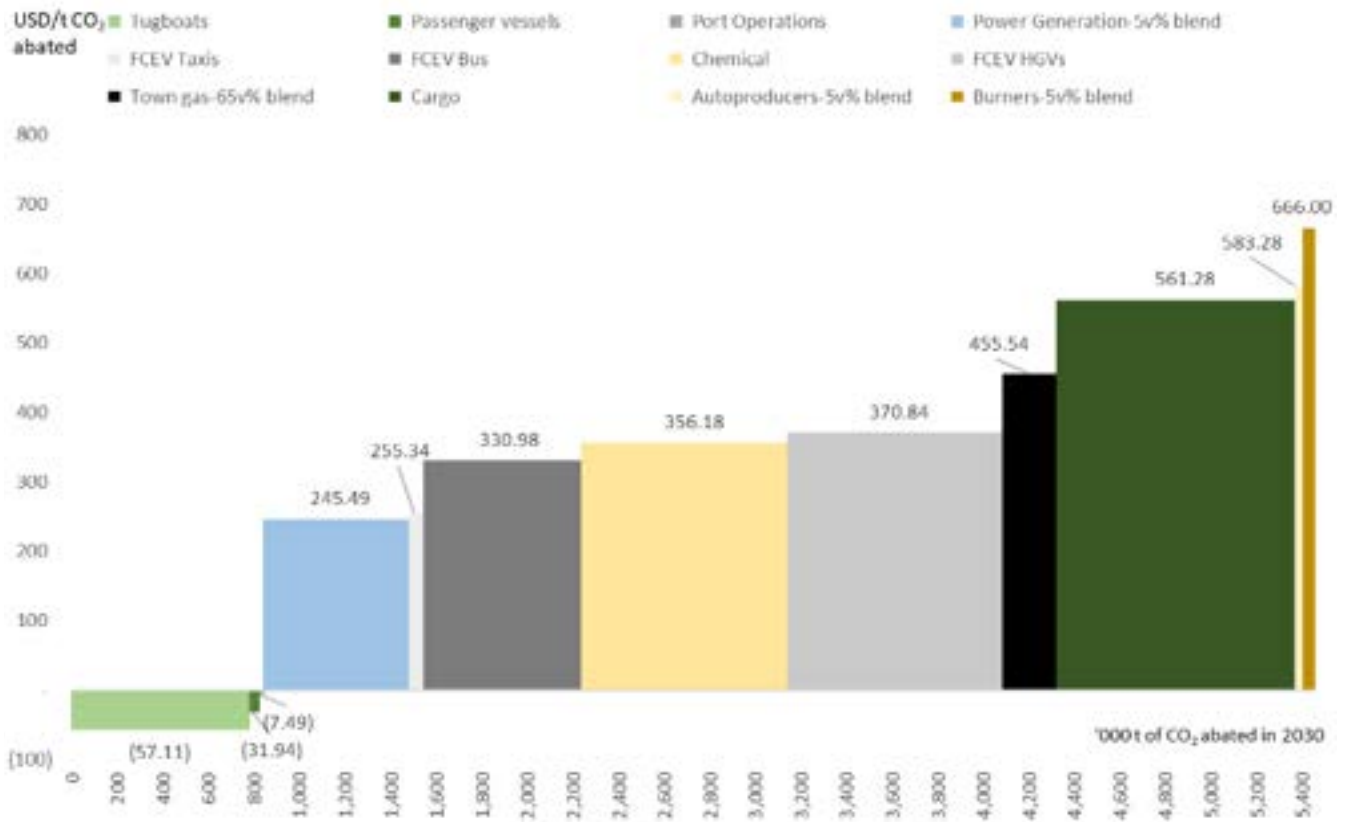


Figure 15.16 - MAC Curve – High Hydrogen Deployment Pathway (2030)

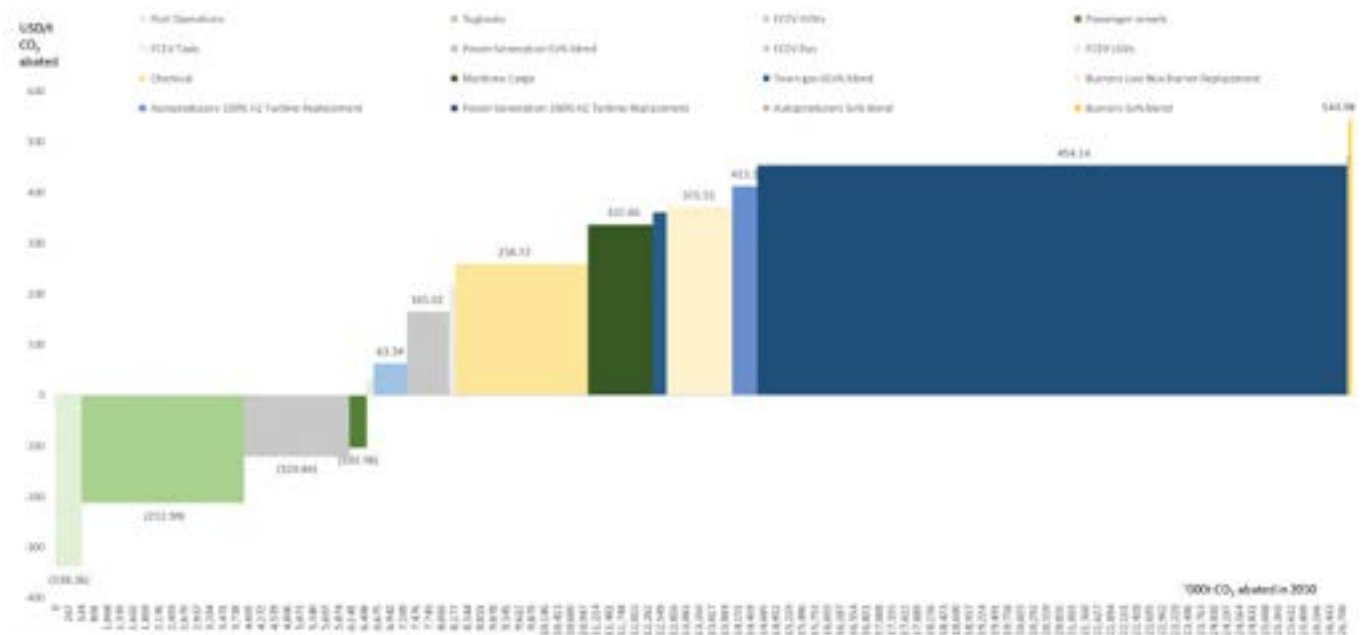


Figure 15.17 - MAC Curve – High Hydrogen Deployment Pathway (2050)

Potential Policy Levers and Signposts to Defray Costs

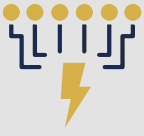
For some downstream sector participants in Singapore, the economics to transition to hydrogen are unfavourable, while options to defray these costs could include relatively high carbon taxes (around USD 500/t CO₂) or long-term government incentives, throughout the forecast period. Since hydrogen deployment costs will be greatly influenced by scalability, a combination of both incentives for first adopters and higher taxes can be used as levers simultaneously. However, risks will be included since the economic forecast of hydrogen deployment does not reach breakeven points over the

forecast period. One of the largest risks includes reducing Singapore's global competitiveness due to higher costs of living / doing business in the country.

Policy and non-policy measures can be put in place to accelerate the adoption of low-carbon hydrogen in the Singapore downstream sector. These measures may need to be combined to reach optimum outcomes for Singapore's chosen level of hydrogen deployment. The potential policy measures, the benefits for accelerating adoption and potential risks are detailed in Table 15.2. These represent possible options arising from the study and do not represent Singapore's current policy position in light of the long-term fiscal sustainability of the options.

Table 15.2 – Supporting Policy Measures, Benefits and Risks

Sector	Potential Policy Measure	Benefits	Potential Risk
 <p>Mobility</p>	Provide an early adopter subsidy scheme with rebate on the additional registration fee for FCEVs.	This will provide a competitive advantage to FCEVs against BEVs and support mass uptake of FCEVs.	-
	BEVs to pay a premium for green electricity.	For BEVs to be truly green they should be drawing green electricity from the grid. This will help to support the Power Generation sector's two-tiered electricity approach and provide another support mechanism for FCEVs against BEVs.	Undermining of green initiative incentives if there is no a clear public understanding of the country's energy vision. Change management programmes to create awareness and understanding of policies and incentives should be implemented to mitigate risks.
	Lower excise duty on hydrogen fuel.	Provide incentives for early adopters of FCEVs through access to cheaper fuel.	This will lead to a loss of tax revenue for Singapore which could inhibit it from making other investments and economic developments.
	Hydrogen refilling station fixed payment guarantees. To facilitate acceleration of FCEV uptake, a network of strategically located hydrogen refilling stations should be planned. However, during initial roll out of FCEV's these facilities may not be used frequently enough to warrant the CAPEX investment, therefore the Singaporean government can provide a guaranteed fixed payment for any refilling station providing hydrogen, despite its utilisation.	The initial investment to convert to hydrogen refilling station is economically viable due to the government guarantee which could accelerate the adoption of hydrogen refilling throughout Singapore.	The rate of adoption of FCEV is not certain and this incentive / guarantee will only be for a limited length of time. Therefore, there is still a risk that the refilling stations will become uneconomic at the end of the scheme.

Sector	Potential Policy Measure	Benefits	Potential Risk
 <p>Power Generation</p>	<p>Two-tier electricity market, for instance:</p> <p>Tier 1: Brown Electricity with hypothetical USD 50 / tCO₂ carbon tax yields LCOE of USD 70 -110 / MWh (depending on natural gas price).</p> <p>Tier 2: Green Electricity from 100% Hydrogen CCGTs yields LCOE of USD 130 to 350 / MWh (depending on landed cost of hydrogen).</p> <p>Consumers who want green electricity will be paying between 46% and 70% more for electricity.</p>	<p>This will allow gencos to price their electricity produced through green hydrogen higher than that produced through natural gas. This will increase the price of electricity for those who are willing to pay for it, e.g. data centers, BEV recharging stations, some domestic consumers.</p>	<p>Under this approach consumers purchasing electricity will be paying between 46% and 70% more for green electricity which is a significant increase and most likely unattractive to many consumers.</p>
	<p>Carbon tax.</p> <p>For a hydrogen landed cost of USD 2 – 4 /kg, the corresponding carbon tax needed for a 100% hydrogen CCGT to reach parity with a conventional natural gas CCGT is USD 200 – 400 /t CO₂.</p> <p>A carbon tax of USD 50 / t CO₂ is needed for a 5%vol HENG CCGT to reach parity with a conventional natural gas ccgt.</p>	<p>A carbon tax could encourage the Power Generation sector to adopt hydrogen to produce green energy. The money generated by the tax could support environmental projects in Singapore or financially incentivise the transition to a hydrogen economy.</p>	<p>A carbon tax will need to be applied universally and may increase the price of electricity for all consumers and in turn increase the price of Singapore's exports in the global market. This could lead to a loss of competitiveness in the region for Singapore.</p>
	<p>Green electricity incentive.</p> <p>The incentive value will match the carbon tax value. i.e. incentives of USD 200 – 400 /t CO₂ not emitted due to burning hydrogen.</p> <p>Or incentive of USD 50 per tonne of mitigated CO₂ for 5vol% hydrogen.</p>	<p>This is the converse to a carbon tax where incentives are provided in the form of tax rebates to gencos which produce green electricity.</p>	<p>As hydrogen does not become competitive with natural gas over the forecast period, this will have to be a long-term incentive.</p>
	<p>Low- to zero-discount rate for green hydrogen CAPEX investments. This will be a loss of tax revenue from the 4% discount rate on CAPEX projects. If all gencos adopt 100% hydrogen CCGTs this could equate to USD 720 million for the Singaporean government by 2050.</p>	<p>This will provide incentives for early adopters of hydrogen turbines and ensure that they are not penalised by the higher cost of equipment.</p>	<p>This incentive may be perceived as providing unequal support across sectors. Other sectors may also require large financing for CAPEX projects to decarbonize.</p>

Sector	Potential Policy Measure	Benefits	Potential Risk
 <p>Industrial</p>	Reduction of corporate tax on profit	This could incentivise the industrial and manufacturing sector to replace fossil fuels with hydrogen.	This will lead to a loss of tax revenue for Singapore which could inhibit it from making other investments and economic developments.
	Carbon tax	<p>A carbon tax could encourage the industry sector to produce or adopt low-carbon hydrogen.</p> <p>The money raised by the tax could support environmental projects in Singapore or financially incentivise industry.</p>	A carbon tax will have to be applied universally and will increase the price of products. This could lead to a loss of competitiveness in the region for Singapore.
	Subsidy scheme for purchasing green hydrogen	This will incentivise the industrial sector to purchase green hydrogen and will also create a market for merchants to import green hydrogen (if available) to supply their existing clients.	Disruption of merchant current operating models and revenue making in Singapore as hydrogen will be supplied from imports. Such a subsidy would not be sustainable in the long term.
	Incentives for green credentials	Green credentials need to be paired with financial incentives for the industry to decarbonise operations and reward green or blue hydrogen adoption.	As hydrogen does not become competitive with natural gas over the forecast period, this will need to be retained over a long term until hydrogen becomes economically viable.
	Incentives for merchants to import green hydrogen into Singapore	Minimise disruption to hydrogen merchant's business positioning in Singapore.	Disruption of merchant operating models in Singapore because hydrogen will be produced overseas. However, this could allow the industry to transition to green hydrogen while maintaining hydrogen supply contracts.



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RD&D Recommendations

"This study includes an assessment to inform and guide the Singapore RD&D community about hydrogen supply chain technologies that have the most potential and as such should be prioritised for further development."



Singapore has an active and highly regarded RD&D community. It is imperative that any RD&D conducted by Singapore in a hydrogen-based economy be focused and effective for deployment of key technologies. The objective of this assessment is to inform and guide the Singaporean RD&D on hydrogen supply chain technologies that have the most potential and should be prioritised for further RD&D development.

KBR conducted a comprehensive review of technologies across the hydrogen supply chain and assessed technological RD&D requirements against Singapore-specific criteria. To determine if and how Singapore could potentially contribute to technological development, the analysis was broken into three different categories based on TRL level:

- TRL 1- 4 Develop: Using this approach the Singapore RD&D community would take ownership development within Singapore and internationally. The benefits of a development approach prove that Singapore can build domestic hydrogen IP capability, export suitable technologies globally, have greater influence over the design and technological integration in the Singaporean context. It can also provide greater influence over the technological development timeline. However, for technological development there is a high level of RD&D investment and high-risk profile.
- TRL 3 -7 Demonstrate: A demonstrate approach would be allocated if the TRL was high enough so that IP ownership existed, but the technology had high deployment potential within Singapore. This approach is envisaged to take the form of a joint venture (JV) or partnership between Singapore academics and local or international technology OEMs or developers. Singapore is used as a hub to test and demonstrate the technology as it progresses through TRL levels. The benefit of a demonstrate approach is that a JV can support accelerated development which both parties may not be able to achieve alone, the costs and risks are spread, and RD&D is aligned around commercialisation of the technology for specific applications. However, there are compatibility problem risks between JV partners and ownership of the technology.
- TRL 6 - 9 Procure: A procure approach is applied when the TRL is high, the technology does not have specific relevance to Singapore, and Singapore has no relevant RD&D expertise to contribute to the development of the technology. Procure also involves customisation and developing capabilities to be an informed buyer and user. The benefits of a procure approach is a reduction in capital risk associated with developing technologies. The procure strategy would mostly be used in scenarios where Singapore requires a technology that is already a commercially viable solution, or a clear pathway for a commercially viable solution. However, the technology may not fit the Singaporean context and also if Singapore has no influence over technology specifications or design.

The results of the RD&D review and the technologies which are recommended for RD&D in Singapore are detailed in Table 16.1.



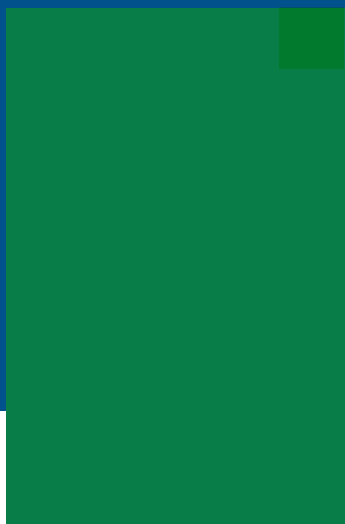
Table 16.1 – RD&D Recommendations

Technology	RD&D Strategy	Benefits	Singapore RD&D
Methane Pyrolysis	Develop/demonstrate	<ul style="list-style-type: none"> The technology has the potential to integrate with Singapore's existing natural gas infrastructure to produce low-carbon hydrogen indigenously as well as to improve Singapore's energy security through the diversification of hydrogen production sources. Further to this, if renewable bio-feedstocks can be sourced, e.g. biogas from wastewater treatment facilities, the process becomes carbon negative. 	<ul style="list-style-type: none"> The main challenges around this technology lies in the development of a cost-effective, regenerative catalyst, and this is where Singapore has RD&D experience.
Solid Oxide Electrolysis (SOE)	Develop	<ul style="list-style-type: none"> SOE is a low TRL and disruptive technology and has the potential to improve electrolyser efficiency to 80% (double that of existing electrolyser) which, in turn, could significantly reduce the cost of producing hydrogen and accelerating its deployment into economies including Singapore. 	<ul style="list-style-type: none"> Singapore has RD&D experience in solid oxide fuel cell technology, which could be transferred to electrolysis, which will give a meaningful chance of establishing the technology.
Liquefied Hydrogen Storage Materials	Develop	<ul style="list-style-type: none"> The materials required for liquification and storage of liquefied hydrogen have significant CAPEX requirements due to the design conditions. 	<ul style="list-style-type: none"> Singapore has specific strengths in this area with local additive manufacturing capability, potential for development of hydrogen storage and transportation materials, especially titanium and its alloys.
Cold Energy Recovery	Develop	<ul style="list-style-type: none"> Boil-off losses and cold energy recovery for hydrogen regassification are also technology barriers for liquified hydrogen. 	<ul style="list-style-type: none"> Singapore has RD&D capabilities and knowledge in modelling and simulation of LNG boil-off and cold energy recovery from regassification and could use these capabilities to develop technologies and solutions to optimise the hydrogen receiving facilities.

Technology	RD&D Strategy	Benefits	Singapore RD&D
Ammonia Cracking	Demonstrate	<ul style="list-style-type: none"> ■ This technology has the potential to significantly impact the hydrogen economy, particularly in Singapore where ammonia is not required for direct use. The areas of RD&D that are required for ammonia cracking are: <ul style="list-style-type: none"> » Development of appropriate catalysts which provide high purity hydrogen; » Increase the efficiency of the process; and » Scaling the technology for commercial applications. 	<ul style="list-style-type: none"> ■ Singapore has significant RD&D capability in catalyst development and has already been involved in developing this technology in partnership with Australia’s CSIRO.
LOHC Dehydrogenation	Procure	<ul style="list-style-type: none"> ■ The RD&D focus areas for LOHCs at large scale globally are: ■ Increasing the dehydrogenation catalyst efficiency; and ■ Increasing the purity of hydrogen liberated. 	<ul style="list-style-type: none"> ■ Singapore should adopt a procure approach to LOHC dehydrogenation technology, where the development of the technology is industry lead and supported by the Singaporean RD&D community.
Hydrogen Fired CCGTs	Demonstrate/Procure	<ul style="list-style-type: none"> ■ Singapore should devote efforts to demonstrate hydrogen fired CCGTs, in order to: ■ Enable the OEMs to conduct rigorous testing in Singapore and scale up the machines with the potential to integrate this testbed into the existing power infrastructure of Singapore; ■ Develop the CCGTs to operate reliably and efficiently in Singapore’s ambient conditions; ■ Build operational capability and understand the unique technical considerations for Singapore’s power sector such as the ability to hot-switch to alternative fuels and perform frequency regulation; and ■ Develop a strategy for strategic fuel stockpiling. 	<ul style="list-style-type: none"> ■ It is recommended that Singapore partners with the OEMs and gencos to demonstrate/procure the hydrogen-fired CCGT technology for utility scale power generation within Singapore.

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Appendix



Fuel Cells for Power Generation

A fuel cell is an electrochemical device that directly converts chemical energy of a fuel and oxidant into electrical energy. This relatively simple, one-step process makes redundant the complex and inefficient multi-step processes found in heat engines (e.g. turbines and internal combustion engines).

Fuel cells have a variety of applications including:

- **Transportation:** fuel cells can be used to provide propulsive power to a vehicle, directly or indirectly (coupled as range extenders) across a variety of transportation options, including cars, trucks, buses, trains, ships, ferries, aircraft and drones.
- **Stationary applications:** fuel cells can be designed and used to provide electricity and heat to buildings, offices, hospitals and other clusters of energy users.
- **Fuel and infrastructure:** infrastructure relates to the equipment and systems needed to produce, distribute, store, monitor and dispense fuel, specifically hydrogen, for fuel cells.
- **Portable applications:** fuel cells can be used to charge or provide power to products that are designed to be moved. These include military applications (portable soldier power, skid-mounted fuel cell generators, etc.), Auxiliary Power Units, laptops and small consumer goods.

For fuel cell applications used in electric power generation within the utility industry, fuel cell efficiencies currently range between 40% to 65% based on hydrogen LHV. This is expected to increase to 80% to 90% depending on the technology used.

Key beneficial features of fuel cell systems over CCGTs are¹:

- Fuel cells have higher efficiencies than engines and gas turbines. Fuel cells can reach up to 80% efficiency, with some technologies having the potential to reach as high as 90%;
- Low temperature fuel cells have quick start up and shut down times compared to traditional CCGTs. Often a few minutes for fuel cells compared with 30 minutes for CCGTs;
- Fuel cells have few moving parts so have lower operating costs and maintenance downtime than CCGTs or engines; and
- Most fuel cells operate silently making them suitable for onsite power generation in residential and hospital buildings.

Key fuel cell system advantages over batteries, include:

- Unlike batteries, fuel cell output power does not deteriorate over time. Lithium-ion batteries deteriorate below 80% capacity after 300 to 500 cycles;
- Operating times for fuel cells are higher than batteries and are dependent on a safe, reliable and secure fuel supply;
- Fuel cells offer constant power over time and do not need to be charged or discharged like batteries; and
- Higher temperature fuel cells produce high-grade process heat along with electricity and are well suited to cogeneration applications (such as combined heat and power for residential use²;
- Installed costs of fuel cells range between USD 5,000 and USD 10,000 per kW of installed capacity, five to ten times the cost of a CCGT power plant fed with natural gas at a cost of approximately USD 1,000 per kW of installed capacity³;
- Increased land requirements compared to conventional CCGTs;
- Fuel cells are sensitive to fuel quality (impurities affect the performance of the fuel cell); and
- Specialist operation and maintenance skills are required; which are rare and often provided by the fuels cell manufacturer.

Fuel Cell Technologies

The following are the major types of fuel cells currently in use or being developed:

- Alkaline fuel cells (AFC);
 - Phosphoric acid fuel cells (PAFC);
 - Proton Exchange membrane (PEM);
 - Molten Carbonate fuel cells (MCFC);
 - Solid oxide fuel cells (SOFC); and
 - Direct methanol fuel cells (DMFC).
- Table 17.1 lists current demonstrated applications of different fuel cell technologies within power generation and CHP. It is noteworthy that all existing utility scale fuel cell technologies are also high temperature.

¹ Viessmann – Fuel Cell Advantages, [<https://www.viessmann.co.uk/heating-advice/what-are-the-advantages-of-fuel-cells>].

² Hydrogen Europe article on heating and cooling, [<https://hydrogeneurope.eu/green-heating-and-cooling>]

³ WSU fuel cells for buildings article, [<https://labs.wsu.edu/cleanenergy/documents/2015/08/energybuildings2015b.pdf>]

Table 17.1 – Current Fuel Cell Applications for Power Generation⁴

FUEL CELL TYPE	APPLICATION
■ PEMFC	Installed residential micro CHP systems
■ SOFC	Large industrial CHP and residential micro-CHP systems
■ MCFC	Large industrial CHP and utility-scale electricity production
■ PAFC	Has been in use since 1970 for commercial scale CHP systems

The fuel cell technologies available have been reviewed for their applicability to Singapore. A summary of commercialisation readiness and application suitability for the various fuel cell technologies follows:

- AFC technology has the best performance when operating on pure hydrogen and oxygen but its carbon monoxide intolerance hinders its suitability for power generation applications.
- PEMFC is most suitable for transportation applications because of its high-power density, fast start-up, high efficiency, and safe handling. PEMFCs are five to ten years away from commercialisation and remain substantially more expensive than AFCs, although this cost differential is expected to decrease over the next decade.
- DMFC is in early stages of technological development.
- PAFC is the most developed, commercially-available fuel cell and operates at intermediate temperatures. PAFC is suitable for CHP applications with high energy efficiency.
- High temperature fuel cells such as MCFC and SOFC are most suitable for cogeneration and combined cycle systems (with gas or steam turbines at the bottoming cycle) for central power generation applications. MCFC and SOFC are five to ten years and 20 years away from commercialisation respectively.

Research & Development

Singapore research institutions NTU, NUS and A*STAR have engaged in various fuel cell RD&D initiatives from

2001 to the present. The Energy Research Institute @NTU (ERI@N) Energy Storage programme has specific research interests which focus on fuel cells for power generation, including the following:

- Grid storage and power distribution;
- Grid balancing;
- Transportation;
- Generator emission control;
- Combined cooling;
- Heat and power for buildings;
- Back-up power for data centres;
- Disaster relief application; and
- On-site generation for remote sites such as islands.

Available land and the cost of catalysts for fuel cell systems represent the biggest hurdles for fuel cell deployment in Singapore. Global and local fuel cell RD&D will likely focus on achieving low-costs and high-performance fuel cell systems.

Fuel Cell Applications

Fuel cells can be used as primary and/or back-up power for stationary applications, including in homes, businesses, telecommunications networks, utilities, hospitals, hotels, airports and train stations. It can be used for both centralised and distributed power applications. Fuel cells in this application offer higher efficiencies than CCGTs; however, they require a larger footprint and higher CAPEX.

Both centralised and distributed fuel cell power generation for Singapore have been reviewed, while land requirements and CAPEX have been assessed. These will be discussed in this section.

Centralised Fuel Cell Power Generation

For bulk power generation, gencos currently require a spinning reserve, as such it is vital that power generation technology start-up time is expedited to reduce spinning reserve investment and footprint. Due to fast start-up times, compared with other fuel cells, PEM fuel cells have been used for this analysis.

⁴ H2FC super gen white paper on fuel cells, [<http://www.h2fcsuper-gen.com/wp-content/uploads/2014/05/H2FC-SUPERGEN-White-Paper-on-Heat-May-2014.pdf>].

Land Requirements for Centralised Fuel Cell Power Generation

Total land requirements for replacing Singapore's CCGT infrastructure with fuel cells for bulk power generation is shown in Table 17.2. This calculation does not include the balance of plant systems.

Table 17.2 – Fuel Cell for Power Generation Land Requirements.

POWER DEMAND	FUEL CELLS LAND REQUIREMENTS	NATURAL GAS CCGT LAND REQUIREMENTS
CURRENT	■ 2.52 km ²	■ 0.75 km ²
2050 DEMAND	■ 3.48 km ²	■ 1.03 km ²

An isolated fuel cell stack is not sufficient to generate electricity. The following infrastructure and equipment are also necessary⁵:

- Fuel supply and/or storage;
- Pumps, compressors, expanders, filters; and
- Safety and control systems.

The footprint required to produce current generational capacity using fuel cells is more than three times that for traditional power generation using natural gas powered CCGTs. It is not feasible to replace bulk power generation with fuel cells despite their increased efficiencies due to land constraints in Singapore. Moreover, there is a significant increase in CAPEX compared to CCGTs. Note that the 60 MW Gyeonggi Green Energy facility in Hwasung City⁶ which is used as a reference in this study, is intended for technology demonstration purposes, and that footprint and land intensity may be dramatically improved as plant configuration and layout enhancements, such as fuel cell stacking are developed. This however may also increase CAPEX.

Distributed Fuel Cell Power Generation

Fuel cells can provide distributed power for remote locations or users with high energy demands. Systems can

supply reliable electricity without facing efficiency losses from long-distance grid transmission or reliance on the grid. Potential likely locations identified for decentralised fuel cell deployment in Singapore include data centres, hospitals and localised residential power.

Distributed fuel cells can also be used for small power requirements such as telecommunication towers and off-grid equipment. This has not been assessed as part of the study because it is not considered to help enable a hydrogen-based economy. However, it may become an option as the hydrogen economy in Singapore matures.

Singapore is a major hub for data centres worldwide. Most data centres host multiple tenants under lease agreements, while large technology firms such as Google, Facebook, Amazon and Microsoft have their own data centres. The data centres are clustered in the East (Tai Seng-Loyang), West (Ayer Rajah-Jurong) and north of Singapore. The majority reside in the western part of the city near Jurong. This is also where subsea cables land⁷.

Data centre power demand is approximately 300 to 400 MW⁷. Data centres in Singapore draw electricity from the open electricity market which allows businesses to source the cheapest electricity available. Data centre operators can either pass this low price through to their customers to attract more business or retain savings and increase profit margins. The data centres rely on back-up generators provided by vendors such as Schneider, ABB, Johnson and Socomek⁷.

Due to high energy demand, data centres have been identified as a potential application for decentralised fuel cells. Older data centres that may be due for upgrades can potentially switch to fuel cells. These facilities could be a first mover in creating initial demand for hydrogen in Singapore.

Benefits of using fuel cells for data centres follow:

- Since there are no land requirements for batteries, saved land can be repurposed. Additionally, this removes OPEX associated with battery replacement and disposal (typically every five years);
- Fuel cells provide clean electricity and data centre operators can leverage this for positive corporate social responsibility (CSR) and to meet sustainability goals; and
- A fuel cell system can be used to heat and/or cool the data centres, while increasing the system's overall efficiency.

⁵ Hydrogen Fuelled Electricity Generation article, [https://www.mpoweruk.com/hydrogen_fuel.htm].

⁶ Power Magazine article on South Korea fuel cell power plant, [<https://www.powermag.com/worlds-largest-fuel-cell-plant-opens-in-south-korea/>].

⁷ Interview, SG Tech.

Challenges associated with using fuel cells for data centres are:

- Logistical challenges and cost associated with transporting hydrogen for distributed fuel cell applications;
- Removes the competitive advantage of an open electricity market where competing operators are sourcing power from the same provider(s)⁸;
- Challenges for all data center cluster tenants to agree to transition to different energy sources;
- Possible resistance from vendors that currently provide the batteries and generators⁸;
- The Singapore Civil Defence Force (SCDF) will need to reverify building fire codes, while facility management will have to be retrained for hydrogen handling and emergency contingencies⁸; and
- Gas turbines or batteries will need to be available for quick change over if fuel supply disruptions occur.

Land Requirements for Distributed Fuel Cell Applications

Estimated land requirements for each of the identified distributed fuel cell applications has been calculated.

Power and footprint requirements for each application are detailed in Table 17.3 below. This calculation only takes into consideration the land required for the fuel cell and does not consider balance of plant.

Table 17.3 – Power and Footprint Requirements for Decentralised Fuel Cell Applications

APPLICATION	POWER REQUIREMENT	FOOTPRINT REQUIREMENT
Data Centre	400 MW	167,000 m ²
HDB Housing	300 kW	30 m ²
Hospital	2 MW	700 m ²

These footprints will add significant land requirements to provide electricity to each application using fuel cells rather than the current configuration of taking energy from the central grid. For data centres with multiple

occupancies, the transition to fuel cells may cause major disruption if these firms cannot reach an agreement over its implementation. A retrofit for older data centres may offer an opportunity to assess the feasibility of adopting fuel cell technology.

Power generation for single-occupancy data centres pose less challenges. However, as mentioned earlier, this could result in the data centre becoming less competitive since it will not have access to the open electricity market and associated low tariffs.

Residential applications: Moreover, it is unlikely that fuel cells will easily retrofit to existing residential facilities due to land constraints. New developments could adopt fuel cells for microgrid powering, particularly those that are in remote areas of Singapore or its islands such as Semakau.

Fuel cell power in hospitals has been rolled out successfully across the US after diesel back-up failed in disaster situations. However, this may be less applicable in Singapore since it is not prone to natural disasters. Specific land space available at Singapore's hospitals should be reviewed in more detail because this application could provide early hydrogen demand.

Fuel Cell Operation and Maintenance

Fuel cell systems have no moving parts and can be operated remotely by the system manufacturer, eliminating the requirement for on-site staff. Fuel cells can operate in environments from -40°C to 50°C without the need for external cooling which would allow them to be easily distributed in Singapore due to its warm climate. The modular nature of fuel cells lend themselves to real-time monitoring and component servicing without downtime. However, they are manufactured using interconnected repeat cells so the failure of a single component such as a membrane can lead to cell failure and, further, to failure of the whole stack⁹.

Hydrogen separation distances found in NFPA 2 Hydrogen Technologies code 2011 states that for a gaseous hydrogen storage system, the separation distance from the lot line can be up to 15 m. This is difficult to achieve in a congested block of HDB apartments located on small plots of land. The fuel cell enclosure has hydrogen sensors to detect any potential hydrogen leaks, however monitoring cannot replace prevention and safe layout design. Safety systems include fail safe operations, with the ability to halt the flow of hydrogen into the fuel cell and evacuate the enclosure in the event of an emergency.

⁸ Interview, SG Tech.

⁹ Junye Wang, Hualin Wang, Yi Fan, Techno-Economic Challenges of Fuel Cell Commercialisation, June 2018, [<https://www.sciencedirect.com/science/article/pii/S2095809917307750>].



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National Climate Change Secretariat,
Strategy Group, Prime Minister's Office

Study of Hydrogen Imports and Downstream Applications for Singapore

