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Power-To-X

Energy Industry Report

The Al-Attiyah Foundation

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INTRODUCTION

'Power-to-X' is the concept of using electricity to produce useful fuels and chemicals from air, water and other basic inputs. Although hardly available today in a commercial manner, Power-to-X has gained interest for two main (and related) purposes: to convert excess renewables to a storable commodity, and to produce low-carbon fuels and materials for hard-to-decarbonise sectors.

What are the available technologies and fuels? And what is their state of technical and commercial viability?

ENERGY REPORT

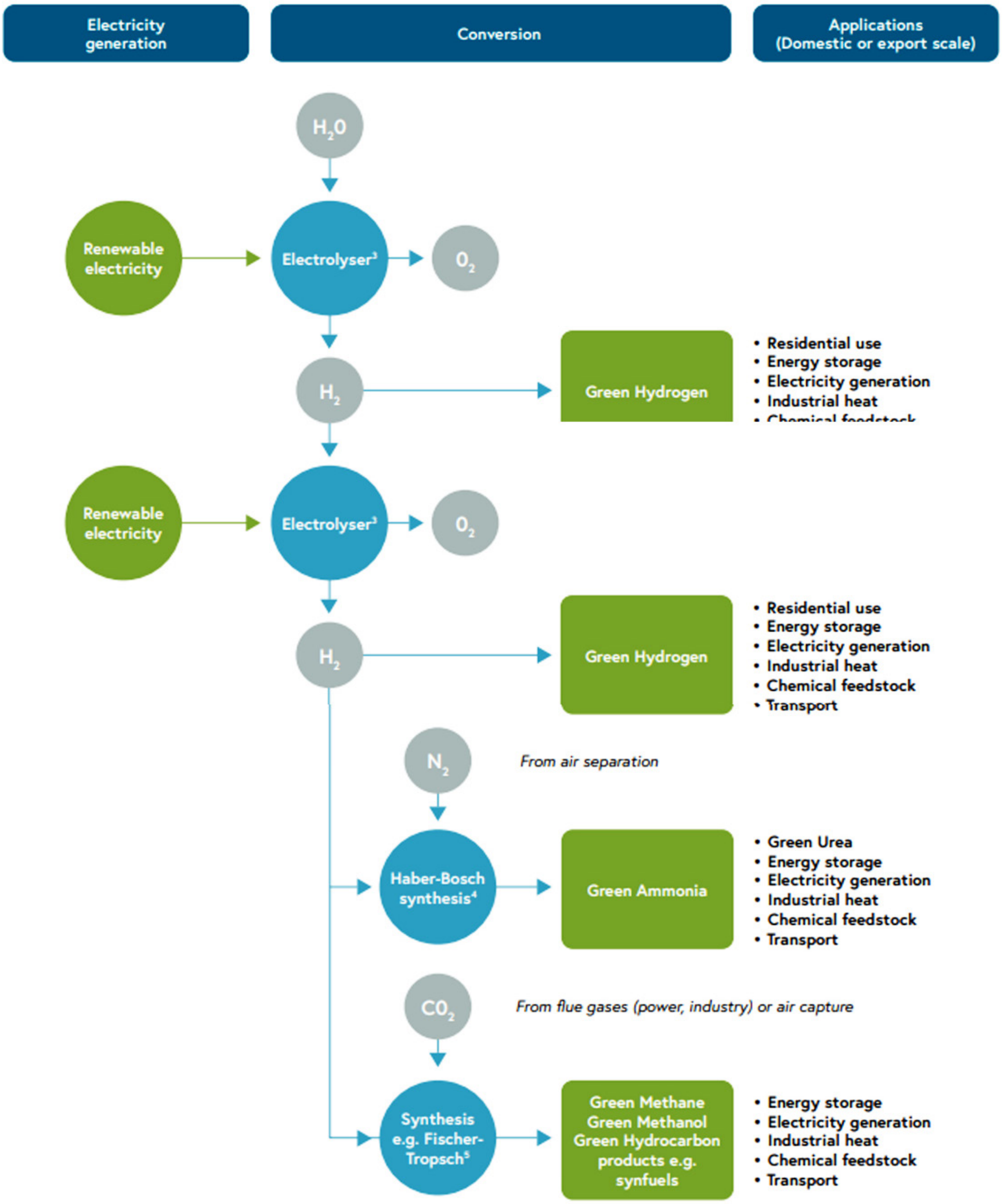
This research paper is part of a 12-month series published by The Al-Attiyah Foundation every year. Each in-depth research paper focuses on a prevalent energy topic that is of interest to The Foundation's members and partners. The 12 technical papers are distributed in hard copy to members, partners, and universities, as well as made available online to all Foundation members.

- Power-to-X is a process through which electricity generated from renewable (or nuclear) sources is used to make hydrogen through electrolysis and used directly as an energy source or converted to synthetic gases and liquid fuels, by combination with atmospheric CO_2 or biomass.
- A key element of Power-to-X is green hydrogen that is converted to synthetic gases through the Power-to-Gas pathway, or as liquid fuel through the Power-to-Liquid pathway.
- Power-to-Hydrogen is a sub-pathway of Power-to-Gas and involves using electrolysis to split water molecules to produce green hydrogen and oxygen using renewable electricity.
- Power-to-X not only opens opportunities to couple various end-uses such as the industrial, transport, power, and heating sectors, but also unlock their decarbonisation potential.
- The central component of Power-to-X technologies is water electrolysis, which uses electricity to split water into hydrogen and oxygen; nitrogen (with hydrogen) into ammonia; and CO_2 and water into carbon monoxide or synthesis gases (syngas).
- Renewable hydrogen can also be utilised through secondary conversion processes such as methanation to generate a range of hydrocarbon products and ammonia.
- Power-to-Methane could be a potential pathway to decarbonise the production of fuels, chemicals and plastics currently derived from fossil fuels.
- Power-to-Ammonia can decarbonise the fossil fuel-intensive production of fertilisers by powering the Haber–Bosch process through renewable electricity, converting nitrogen and hydrogen into ammonia using electrolysis.
- Power-to-Methanol converts CO_2 to produce methanol, an energy-dense liquid fuel that can be easily stored, transported and utilised for chemicals.
- Early opportunities for Power-to-X technologies are likely to be in small-scale applications (kW scale), before they transition to commercial and industry applications (MW scale), ultimately landing at large hydrogen hubs or clusters that are vital components of the national energy mix (GW scale).
- A decline in levelised cost of electricity from renewables, combined with increased load factors and lifetimes of electrolysis units, and a fall in their capital costs, will lead to competitive costs for green hydrogen production across various geographies.

Power-to-X (PTX) or renewable Power-to-X is a process through which electricity generated from renewable sources is converted to hydrogen through electrolysis and used directly as an energy source or converted to synthetic gases and liquid fuels.

PTX is an emerging and increasingly viable platform to store excess electricity for subsequent dispatch and end-use as well as providing a low capital-intensive decarbonisation pathway to produce green energy sources, fuels, and chemicals.

Figure 1. Power-to-X Pathways



PTX allows abundant and underutilised renewable resources such as solar and wind to power electrolysis technologies that are capable of converting excess molecules from water to hydrogen, carbon dioxide (CO_2) and water to methane and syngas, and air and water into hydrogen peroxide (H2O2) and ammonia.

These energy carriers and fuel sources not only provide versatility in energy storage, but they also smooth the intermittency of renewable generation, and provide various pathways to decarbonisation.

PTX also offers numerous advantages over traditional energy storage systems such as battery storage systems and pumped hydropower, which cannot be transported over large geographical distances. Green products produced through the Power-to-Gas (PTG) and Power-to-Liquids (PTL) pathway such as e-Methanol, e-Methane, and e-Ammonia can be used for residential use, energy storage, electricity generation, industrial heat, feedstock for chemicals and fertiliser production, and in hard-to-abate mobility such as aviation and maritime shipping.

An essential component of PTX pathways is renewable hydrogen (or 'green' hydrogen) produced through electrolysis of water powered by renewable electricity, thereafter, converted to synthetic gases (syngas) through the PTG pathway, or liquid fuel through the PTL pathway.

It is important to note that hydrogen is an energy carrier and not a source of energy. Hydrogen can be produced from a wide variety of energy sources. Historically, it has been mainly produced from fossil sources such as coal (brown hydrogen), oil or natural gas (grey hydrogen), or natural gas with carbon capture and storage (blue hydrogen).

In a low-carbon energy future, hydrogen offers new pathways to utilise renewable electricity. Hydrogen and renewable electricity as energy carriers are expected to play a complementary role in the ongoing energy transition. Green hydrogen has the potential to channel large amounts of renewable electricity to industries and sectors that are hard to decarbonise.

In the industrial sector, grey and blue hydrogen is widely used across various refineries and industrial processes to produce oil products, methanol, ammonia, bulk and speciality chemicals. In the longer-term, green hydrogen may be able to replace hydrogen produced from fossil fuels as feedstock across these CO_2 intensive applications.

Hydrogen injected in the natural gas grid has the potential to reduce natural gas consumption across the building and power sector, which could also be an additional source of revenue beyond hydrogen sales to the transport or industrial sector. However, this is a relatively low-value use of hydrogen and, at higher levels of blending, requires retrofits of existing gas distribution. As hydrogen injections in the natural gas system increase, in the short-term it may encourage additional volumes of hydrogen production, which could trigger further cost reductions through economies of scale, and improve the cost competitiveness of producing green hydrogen.

For a long time, the transport sector has seemed a promising area for hydrogen expansion. Fuel cell electric vehicles (FCEVs) are low carbon mobility options with the driving performances of conventional vehicles. However, it would appear that battery-electric vehicles (BEVs) will be superior in cost for passenger applications, with FCEVs possibly being more suitable for heavy freight.

For long distance shipping, battery electric propulsion systems may not be viable, and hydrogen stored as ammonia or methanol could be commercially viable option to replace marine fuel oil.

Aviation is one of the hardest modes of transportation to decarbonise due to the requirement for energy-dense fuels used by aircraft engines to minimise weight, and the demanding performance specifications. Synthetic jet fuel produced via PTL could be a suitable option to decarbonise air transport.

The increasing use of renewables for electricity generation to power various end-uses across the industrial, transport and power sectors not only opens opportunities to couple these sectors, but also unlocks their decarbonisation potential.

In the current fossil fuel-dominated energy system, decarbonisation efforts across the industrial, power, heating, and transport sector are largely separate. However, in order to reach net zero emissions by 2050, these individual sectors have to be integrated or coupled to provide renewable electricity to decarbonise end-use. This also provides extra flexibility to accommodate increasing intermittent renewable electricity in the power system and reduces levels of curtailment for renewable energy.

PTX pathways could also enable faster electrification of the energy system beyond what is possible through direct electrification. The International Energy Agency (IEA) under its Sustainable Development Scenario (SDS) forecasts renewables to account for 73% of the global electricity mix by 2050, which will have to increase by an additional 300% by 2050 in order to provide power for PTX technologies[i].

The first step of any PTX pathway is to convert renewable electricity to green hydrogen through electrolysis. Electrolysis was first introduced in 1834 when British scientist Michael Faraday discovered water molecules could be split into oxygen and hydrogen by an electric current.

A central component of PTX technologies is water electrolysis, which uses electricity to split water into hydrogen and oxygen; nitrogen (with hydrogen) into ammonia; and CO_2 and water into carbon monoxide or synthesis gases (syngas).

Water electrolysis involves the dissociation of fresh water, seawater, or wastewater into hydrogen and oxygen. The hydrogen production process has been well known over the last century given the production of brown, grey, and blue hydrogen. However, green hydrogen is an emerging opportunity.

In water electrolysis, the disassociation of water occurs in the electrolysis cells, which contains water, electrodes, and an electrolyte material carrying an electrical current. Hydrogen and oxygen are produced separately in the cathode and anode section of the cell. The electrolyte material ensures the transfer of ions from the anode to the cathode and is separated by a membrane. The size of the cell is limited by the capacity of the membrane to handle the electric current.

Table 1: Technical / Economic Specification of AEC Electrolysers

AEC Electrolysers			
	Units	2017	2025
Efficiency	kWh of electricity / kg of H2	51	49
Efficiency (lower heating value)	%	65	68
Lifetime Stack	Operating Hours	80,000	90,000
CAPEX (Total System Cost + Power Supply + Installation)	EUR / kWh	750	480
OPEX	% of initial CAPEX / year	2%	2%
CAPEX – Stack Replacement	EUR / kWh	340	215
Total Output Pressure	Bar	Atmospheric	15
System Lifeline	Years	20	20

Electrolysis cells are piled in stacks that comprise the core of an electrolyser, which in turn consists of auxiliary components such as a current rectifier, a water demineralisation unit, a water pump, cooling system, hydrogen purification unit, and instrumentation.

There are three main types of electrolysers used for hydrogen production: Alkaline Electrolysis Cells (AEC) is the most technologically mature technology compared to Proton Exchange Membrane Electrolysis Cells (PEM). Solid Oxide Electrolysis Cells (SOEC) are at an early stage of development.

AEC technologies use an alkaline solution such as sodium hydroxide or potassium hydroxide as an electrolyte to transfer electrons through hydroxide anions. Depending on the capacity of the electrolysers and the pressure of the hydrogen that is produced, the energy efficiency of AEC technologies ranges between 65% - 70% (that is 49 – 51 kWh / kg of H2) and their installation capital expenditure (CAPEX) ranges between 500 – 750 EUR / kWh[ii]. Performance is anticipated to improve by 2025, as shown in Table 1. Recent papers suggest a breakthrough with much higher efficiency but remain to be demonstrated practically[iii].

Norway-based NEL and Hydrogen Pro are two large producers of AEC electrolysers. Their electrolysers are mainly used across pilot- to demonstration-stage PTG projects. Their competitors include US-based AquaHydrex, France-based McPhy Energy, Germany-based Thyssenkrupp, and China-based Tianjin.

Technology improvements for AEC electrolysers do exist but are incremental. Reducing cost of production and improving energy efficiency are the main priorities of AEC technology manufacturers, which they typically pursue through economies of scale from large-scale production.

PEM electrolysers are a rapidly emerging technology and are increasingly entering commercial deployment. These technologies use proton transfer polymer membranes that play a simultaneous role of electrolyte and separation material between the anode and cathode section of the electrolysis cell.

PEM electrolysers have a higher CAPEX than AEC electrolysers. However, further developments in their system design could make them cost-competitive with AEC electrolysers given their compactness, suitability of stack pressurisation, and flexibility of stacks to accommodate fluctuations in solar and wind.

Until now, some CAPEX reduction has been achieved by reducing the use of scarce material on membranes, but future cost reductions will be attributed to an increase in membrane surface and cell stack throughput. Technology developers estimate CAPEX installation costs of a 10 MW unit to decline to EUR 700 / kW in 2025 and possibly EUR 400 / kW in 2050[iv].

Manufacturers of PEM electrolysers are very active in the development of this technology and its applications in PTG projects. The two largest developers of PEM electrolysers are UK-based ITM Power and Germany-based Siemens Energy.

Finally, SOEC electrolysers operate at higher temperatures ranging between 700°C- 800°C, which allows these electrolysers to minimise electricity used for the electrolysis. These electrolysers use ceramic materials for electrolytes and electrode material, and the electron transfer between the anode and cathode section of the cell is driven by oxide anions through the ceramic material.

SOEC electrolysers may turn out to be a game-changing technology in the medium term given its advantages such as increased conversion efficiency, the potential use of waste heat, and the possibility of producing a synthesis gas directly from steam and CO_2 for use in various applications such as synthetic liquid fuels.

However, SOEC electrolysers are at an early stage of deployment and their costs have not been established. SOEC manufacturers such as Germany-based Sunfire have developed a 200 kW stack pressured at 30 bar that can be integrated with a methanation reactor or for power-to-liquids (PTL) applications[v].

Table 2: Technical / Economic Specification of PEM Electrolysers

PEM Electrolysers			
	Units	**2017**	**2025**
Efficiency	kWh of electricity / kg of H2	58	52
Efficiency (lower heating value)	%	57	64
Lifetime Stack	Operating Hours	40,000	50,000
CAPEX (Total System Cost + Power Supply + Installation)	EUR / kWh	1,200	700
OPEX	% of initial CAPEX / year	2%	2%
CAPEX – Stack Replacement	EUR / kWh	420	210
Total Output Pressure	Bar	30	60
System	Years	20	20

Renewable hydrogen can also be utilised through secondary conversion processes such as methanation to generate a range of hydrocarbon products and ammonia.

Methanation involves the synthesis of methane by hydrogenation of CO or CO_2. In case of the former, methanation through catalytic processes is typically used for ammonia synthesis in coal-to-gas or liquids processes, or for natural gas processing in the oil & gas industry. Methanation occurs through two different processes: catalytic methanation or biological methanation.

Catalytic methanation is a thermochemical process that occurs on a catalyst at a temperature between 200°C - 700°C and pressures between 1 and 100 bars. The reaction is highly exothermic, and temperature must be controlled to avoid thermodynamic limitation of the reaction and catalyst degradation.

The CAPEX for a catalytic methanation unit in a PTG unit can varies significantly between EUR 400 / kW – EUR 1,500 / kW[vi]. The large CAPEX range is due to low commercial deployment to date. The isothermal reactors used in catalytic methanation units typically face technical challenges relating to temperature control and operational flexibility. However, improvements in reactor design and reactor cooling systems will lead to additional cost reductions.

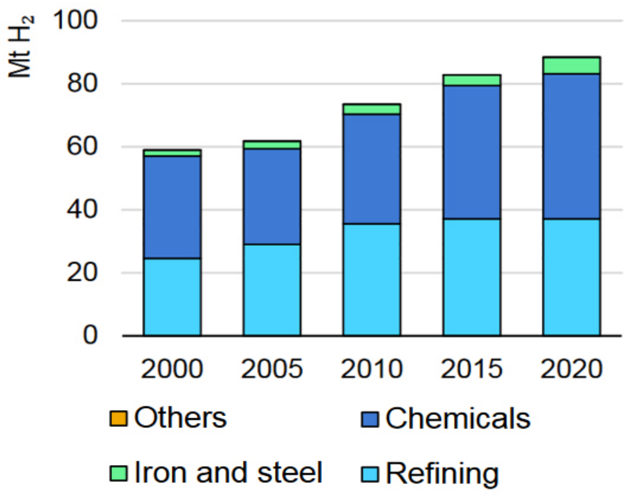
Biological methanation is an emerging process and an alternative to catalytic units. The process produces methane from hydrogen and CO_2 using methanogenic organisms that act as biocatalysts. The entire process occurs under anaerobic conditions in an aqueous solution at an atmospheric pressure between 20ºC – 70ºC.

Biological methanation is still in its early stage and has the potential to dramatically reduce costs given its simple reactor design and convenient pressure and temperature conditions. However, the process has to overcome several barriers, such as the gas / liquid interface of the reaction medium, which is a strong barrier for mass transfer within the reactor and limits the effective kinetics of the reaction[vii]. Also, the reaction must occur in specific pH conditions, which restrict the control of its kinetics by increasing hydrogen or CO_2 concentration in the reactor[viii].

An example of a project with a catalytic methanation unit is the P2G-BioCat Pilot Project in Denmark. The objective is to design, engineer, construct, and operate a 1 MW PTG facility that produces and injects grid-quality methane under intermittent operations using hydrogen from alkaline electrolysis and a methanation reactor based on biological catalysis[ix]. The project has allowed the development consortium (which consists of Hydrogenics, NEAS Energy, Audi AG, and Biofos) to understand the biological methanation process, its integration with an electrolyser, operating constraints, and associated business opportunities in the context of Denmark's energy system.

PTG is the process of converting renewable electricity to gaseous carriers such as hydrogen, methane, or ammonia. PTG uses electrolysis to generate hydrogen from renewable electricity, which is then reacted with CO_2 in the presence of bio-catalysts to produce methane.

Figure 2: Global Hydrogen Production[xiii]



Similar to PTG, PTL involves reacting hydrogen produced from an electrolysis process with CO_2 to produce liquid fuels such as synthetic crude, diesel and jet fuel. These electrofuels or e-fuels can replace conventional fossil fuels without the need to change their end-use process or technologies. Also, hydrogen can be used as feedstock to produce bulk chemicals (Power-to-Chemicals), such as methanol or ammonia that are used in the industrial sector.

Another PTX pathway is Power-to-Heat (PTH) through which renewable electricity is used to generate heat via heat pumps or large electric boilers. Heat pumps use electricity to transfer heat from sources such as air, water, or ground to buildings. Heat pumps can also be used for demand-side management applications such as electricity load shifting and peak load management. Like other PTX pathways, PTH can use surplus electricity to address heating demand and avoid the curtailment of renewable electricity generation.

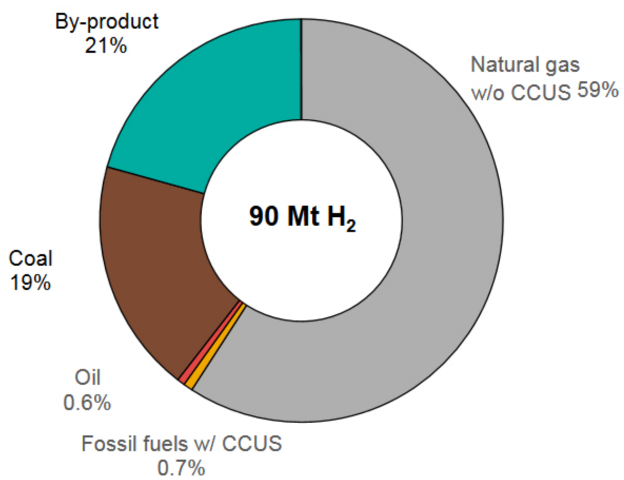
Power-to-Hydrogen (PTH2) is a sub-pathway of PTG and involves using electrolysis to split water molecules to produce green hydrogen and oxygen using renewable electricity.

Currently, most of the hydrogen produced is used as industrial feedstock for the production of ammonia and methanol, while the remaining is used to refine oil. In addition to replacing current hydrogen use in the industrial sector, green hydrogen produced from PTG can be used as a replacement fuel for heavy fuel oil, marine fuel, and jet fuel; as well to store and re-generate electricity.

Global hydrogen production stands at 90 MtH2 and 59% of the of the supply is produced from natural gas as an input source (i.e. blue hydrogen)[x]. In addition to this, 79% of the global supply comes from dedicated hydrogen production projects, whereas the remainder is produced as a by-product at various oil & gas refineries[xi]. Hydrogen demand for ammonia production and oil refining stands at 72 MtH2 while 18 MtH2 was mixed with other gases for Direct Reduced Iron (DRI) in steel production and methanol production[xii].

Most of the hydrogen is produced from Steam Methane Reforming (SMR) – a process through which steam reacts with natural gas to produce synthetic gas, which is a mixture of hydrogen and carbon monoxide (CO). The CO is shifted to CO_2, which is usually emitted in the atmosphere. However, if the CO_2 is sequestered through carbon capture, utilisation, and storage (CCUS) technologies, hydrogen produced from fossil fuels can contribute to the global supply of low-carbon hydrogen.

Figure 3: Sources of Hydrogen Production[xiv]



In recent times, most of the research and development relating to green hydrogen production has been focused on using clean water as input source. However, due to the droughts and lack of fresh water in regions such as Australia, the Middle East, and China, electrolyser manufacturers are increasingly exploring the utilisation of seawater or wastewater, which has presented its own challenges such as membrane stability, because of impurities. As the chemistry and the learning experience of these technologies improves, they may be able to address water purity issues and extract further cost reductions.

The world's largest operational green hydrogen project is Air Liquide's 20 MW Bécancour facility in Quebec, Canada, which uses a PEM electrolyser supplied by US-based Cummins and is powered by local hydroelectricity.

US-based Air Products is building a green hydrogen project in Saudi Arabia, which will be powered by 4 GW of wind and solar power. The project will cost US$ 5 bn and will be jointly owned by Air Products, ACWA Power, and Neom (a new mega-city planned near Saudi Arabia's borders with Egypt and Jordan).

Another sub-pathway of PTG is Power-to-Methane (PTCH4). Given the global demand for chemicals, fuels, and petroleum products derived from fossil fuels, PTCH4 could be a potential pathway to decarbonise methane production using renewable hydrogen.

Methane is the main component of natural gas, which in itself is an important part of the global electricity mix, industrial uses such as food processing and fertiliser production, feedstock to produce methanol and ammonia, and heating and cooking in the commercial and residential sector.

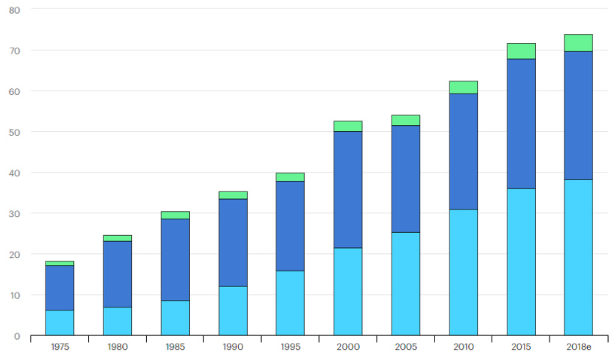
Green methane can substitute for natural gas and could replace several existing important uses such as process heating, energy storage and regeneration of electricity, and other residential and commercial uses such as heating and cooking.

Green methane is produced by combining green hydrogen with green CO_2 through a methanation process (which is also known as the Sabatier Reaction). CO_2 methanation is widely used in refineries that produce hydrogen and CO_2 from fossil fuels[xv].

'Green' methane could be transported through the existing natural gas infrastructure without any changes required. It could use existing natural gas pipes, boilers, appliances and other equipment, and be used to generate electricity at existing gas-fired power projects. In many ways, green methane is a perfect PTX pathway and a seamless substitute for exiting uses of natural gas.

Following PTCH4 with green hydrogen could increase global hydrogen use. However, the main factor that restricts the expansion of methane and its use, is the economic viability of CO_2 methanation and the cost of production, which could be improved by utilising transition metals such as copper and iron as catalysts, that enhance methane production at higher temperatures. Some estimates suggest that improvements in optimisation and system engineering may result in the cost of synthetic methane's falling to ~US$ 20 / GJ ($21 / MMBtu), which could make it potentially competitive with conventional natural gas, as, allowing for carbon prices, this approaches the upper end of LNG prices[xvi].

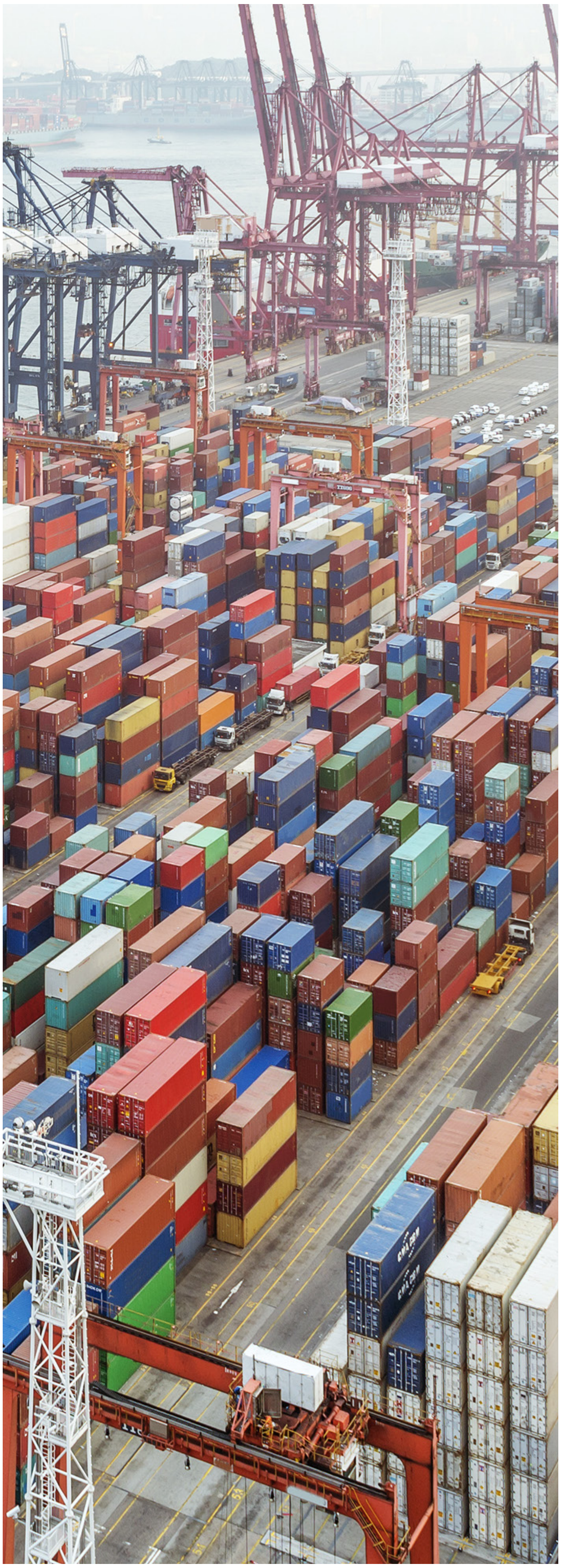
Figure 4: Global Demand for Pure Hydrogen and Ammonia[xix]



Moreover, solar methanation units powered with renewables, combined with feedstock sourced through CO_2 capture technologies, could prove to be a cost-effective system.

Power-to-Ammonia (PTNH3) is another sub-pathway of PTG. PTNH3 provides an opportunity to decarbonise the fossil fuel-intensive production of ammonia fertilisers by powering the Haber–Bosch process through renewable electricity, converting nitrogen into ammonia using electrolysis, or by capturing nitrogen oxide from power projects and reducing it to ammonia.

Ammonia is an important input feedstock for mineral nitrogen fertilisers and forms a bridge between the nitrogen in the air and the food we eat. It is estimated that 70% of the



global ammonia supply is used for fertilisers production, whilst the remainder is used to produce plastics, explosives, synthetic fibres, and textiles; in addition to being used in industrial processes such as refrigerant gas to purify water[xvii].

Global ammonia supply accounts for ~2% of total final energy consumption and ~1% of CO_2 emissions from the global energy system[xviii]. Demand for ammonia will rise with a growing global population and food demand, during a time where CO_2 and GHG emissions from the energy system should be heading towards net zero.

Ammonia has the potential to be a low carbon energy carrier across a variety of applications. A key advantage of ammonia over hydrogen is its higher volumetric energy density and liquefaction temperature, which makes it much easier to transport and store. In 2020, 185 MtNH3 was produced and ~20 MtNH3 was globally traded[xx]. Therefore, when compared to hydrogen, the infrastructure to support storage, distribution, and export of ammonia are already highly developed.

Ammonia could also be used in the power sector. Countries with a limited access to low carbon resources to generate electricity could use ammonia as a vector for hydrogen imports. Ammonia can be produced in countries with abundant renewables or through low cost natural gas, and shipped at relatively low cost to importing countries. The fuel source can also be used as a seasonal storage medium for the power sector through which surplus electricity can be re-converted into ammonia and used in power projects during times when renewable resources are scarce.

Ammonia production involves two main steps: firstly, isolating hydrogen, and secondly, the Haber-Bosch process through which the hydrogen is reacted with nitrogen from the air to produce ammonia. Currently, almost all global ammonia production units are powered by a fossil fuel-based electricity supply, and their hydrogen supply comes from fossil fuel-based feedstocks.

However, a number of PTNH3 pathways are being explored to decarbonise ammonia production. These include using renewable hydrogen to power the Haber-Bosch process; converting nitrogen into ammonia using electrolysis (e-Nitrogen); synthesis of ammonia from air and water; oxidation of pure air to nitrate and then subsequently reducing it to ammonia; and capturing nitrogen from power projects in the form of nitrates and eventually reducing them to ammonia.

Among these pathways, the use of green hydrogen as input to the Haber-Bosch process is increasingly sought, which has the potential to improve the energy efficiency of the process from 15 kWh / kgNH3 to 8 kWh / kgNH3, by increasing the efficiency of the water splitting process and utilising alternative separation techniques such as adsorption[xxi].

In the UAE, Khalifa Industrial Zone Abu Dhabi (KIZAD) has announced plans to build a US$ 1 bn green ammonia facility in the KIZAD free zone targeting regional and international markets. The project will be developed by Helios Industry, a privately-owned special project vehicle (SPV) and will invest to develop the facility over several years in two phases to eventually produce 200,000 tonnes of green ammonia. The green ammonia will be produced from 40,000 tonnes of hydrogen and will be powered by an 800 MW solar power project.

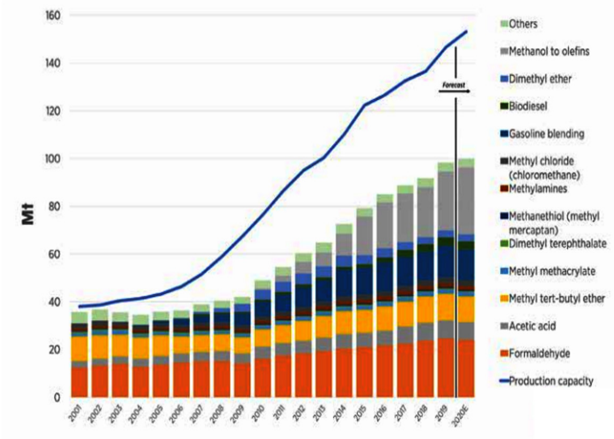
Power-to-Methanol (PTCH3OH) is a sub-pathway of PTL. PTCH3OH involves the conversion of CO_2 to produce methanol, an energy-dense liquid fuel that can be stored, transported, and utilised for chemicals and petrochemicals production.

Green methanol can be produced by combining green CO_2 and green hydrogen, which results in water as a by-product. Green methanol can replace a range of existing uses as a feedstock to produce acetic acid, olefins, and formaldehyde. These chemicals are used to produce adhesives, foams, resins, and solvents, and ultimately, to make consumer products, such as textiles, clothing, home furniture, and wallpaper.

In addition to this, green methanol could also replace conventional methanol that is used as transport fuel for maritime ships or blended with petroleum (which is common practice in China and Southeast Asia).

Green methanol can be produced using renewables or renewable feedstock through two different routes: bio-methanol produced from biomass, or by using CO_2 captured from direct air or CCUS projects which is then reacted with green hydrogen. Currently, ~0.2 green MtCHOH3 is produced annually, mostly from bio-feedstocks[xxii].

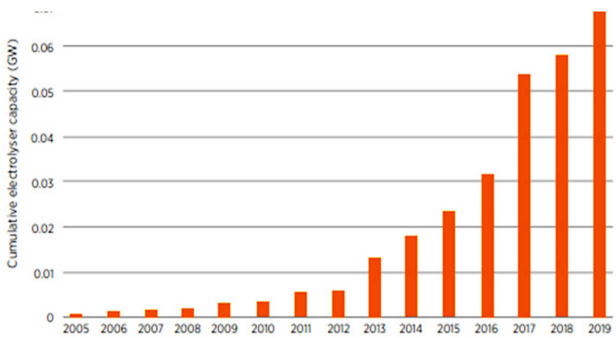
Figure 5: Global Methanol Demand and Production Capacity[xxiii]



Since production is low, limited data is available on actual costs of producing green methanol, and therefore future costs need to be estimated. Bio-methanol production cost mainly depends on the cost of bio-feedstock, investment cost of the production unit, and the efficiency of the conversion processes.

However, the cost of green methanol production via the PTCH3OH pathway depends largely on the cost of hydrogen and CO_2. Current production costs are estimated to be between US$ 800 – US$ 1,600 / tonne assuming the CO_2 is sourced from bioenergy projects with CCUS technologies at a cost of US$ 10 – US$ 50 / tonne[xxiv]. But if the CO_2 is sourced from direct air, CO_2 capture costs range between US$ 300 – US$ 600 / tonne, and the subsequent cost of green methanol production costs ranges between US$ 1,200 – 2,400 / tonne[xxv]. For comparison, posted prices for conventional methanol in March 2022 were around $500 per tonne[xxvi].

Figure 6: Global Electrolyser Capacity[xxviii]



Nonetheless, the future costs of producing green methanol through the PTCH3OH pathway depends on the combination of further reductions in the cost of renewable electricity, the cost of electrolysers, and their efficiency gains and durability.

In Denmark, European Energy is developing a large-scale commercial e-methanol production facility with the hydrogen produced from a 50 MW electrolyser unite supplied by Siemens Energy.

The economic benefits of PTX projects are well-recognised by government regulators and the global energy value chain, particularly international oil companies that are increasingly decarbonising their portfolios and positioning themselves to be at the forefront of the global energy transition. As of 2019, there are ~190 PTX projects across 32 countries, with most of them in pilot or early stage[xxvii].

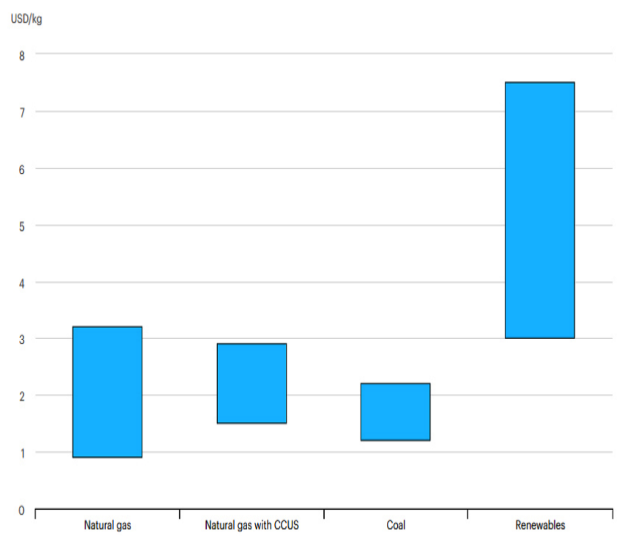
As government regulators, projects developers, and technology manufacturers gain learning experiences on PTG and PTL pathways, this will improve the commercial viability of future projects. Early opportunities for PTX technologies are likely to be in small-scale applications (kW scale), before they transition to commercial and industry applications (MW scale), ultimately landing at large PTX hubs or clusters that are vital components of the national energy mix (GW scale).

Shell is currently developing various integrated hydrogen hubs that serve the industrial and transport sector. The company has entered into an agreement with Aker Clean Hydrogen and CapeOmega to develop, build, and operate a large-scale clean hydrogen hub in Aukra, Norway.

In 2021, Shell began operations at Shell's Energy and Chemicals Park in Rheinland, Germany producing green hydrogen. The project is part of a plan by Shell to turn five local refineries into energy and chemicals parks, which will focus on chemicals, and lower-carbon energy products such as biofuels and hydrogen.

The levelised cost of producing hydrogen is single most factor that will determine the commercial viability of PTG and PTL projects. Currently the cost of producing green hydrogen is ~2x – 3x higher than hydrogen produced from fossil fuels.

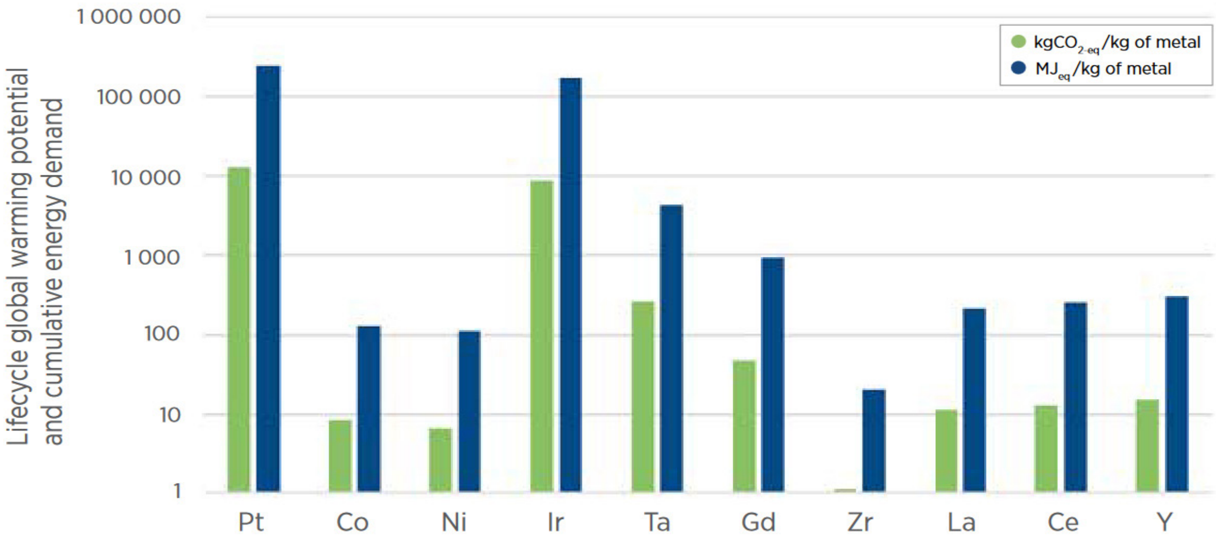
Figure 7: Hydrogen Production Costs[xxix]



However, a decline in electrolyser CAPEX, levelised cost of electricity (LCOE) from renewables, combined with an increase in efficiency and operating lifetime (load factor) could lead to competitive levelised costs (LCOH) for producing green hydrogen across various geographies.

Further reductions in electrolyser CAPEX will be an important driver in reducing the cost of producing hydrogen for PTX projects. There are four main ways through which electrolyser manufacturers and project developers could unlock CAPEX reductions: by improving electrolyser designs, gaining economies of scale through large-scale production, minimising the use of scarce materials and metals, and boosting their energy efficiency.

Figure 8: Global Warming Potential and Cumulative Demand for Critical Materials used in Electrolysers[xxx]



In terms of improving the design of electrolysers and their cell composition, and increasing module sizes, cost reductions are likely to be driven by research and development efforts by technology manufacturers that aim to standardise and simplifying their manufacturing process, improve energy efficiency, and increase the durability of electrolyser components.

By expanding module sizes, manufacturers could achieve economies of scale, as less production units are deployed to produce to large modules sizes. These cost benefits will further increase, if their current stack production levels expand to a GW-scale, which will allow manufacturers to unlock additional cost reduction potential.

Minimising the use of scarce materials and metals used to produce electrolysers could also help reduce their cost of manufacturing electrolysers. PEM, AEC, and SOEC electrolysers require large amounts of critical materials such as nickel, platinum and iridium. These metals could be replaced with other metals such as titanium, cerium, and yttrium.

Electricity supply for electrolysis is a significant cost component with great potential for reductions. The electricity supply for a small-scale electrolysis unit is often sold as package by the electrolyser technology manufacturer, but a customised electricity system designs can be acquired from an engineering, procurement and construction (EPC) company.

As the size of the electrolysis unit increase and standalone / decentralised utility-scale electricity supply systems become available, this can significantly reduce their marginal cost. In addition, the electricity supply can be optimised by careful system integration of different components across the facility, and efficiency gains in different parts of the electrolysis facility can be leveraged to reduce the cost of producing hydrogen.

Another important factor that will determine the LCOH for green hydrogen is the LCOE from renewables that is needed to power the electrolysis unit. Over the last few years, the cost of renewable electricity generation has declined dramatically, with utility-scale solar PV and onshore wind reaching cost levels ranging between US$c 2 – 3 / kWh across a number of countries[xxxi].

Moreover, the higher the load factor (or utilisation rate) for the electrolysis unit, the lower the LCOH (assuming the project CAPEX costs are covered by a higher quantity of hydrogen output). Electrolysis units should generally operate at a load factor of 50% at today's investment levels, but optimal hydrogen costs could also be achieved at ~35%[xxxii].

Nonetheless, the ideal case for producing low-cost green hydrogen involves a low LCOE from renewables with a high load factor, which effectively make the best use of cheap renewable electricity and minimises the impact of electrolyser CAPEX and its amortisation on the LCOH.

Figure 9: Hydrogen Supply as Function of Electrolyser Load Factor[xxxiii]

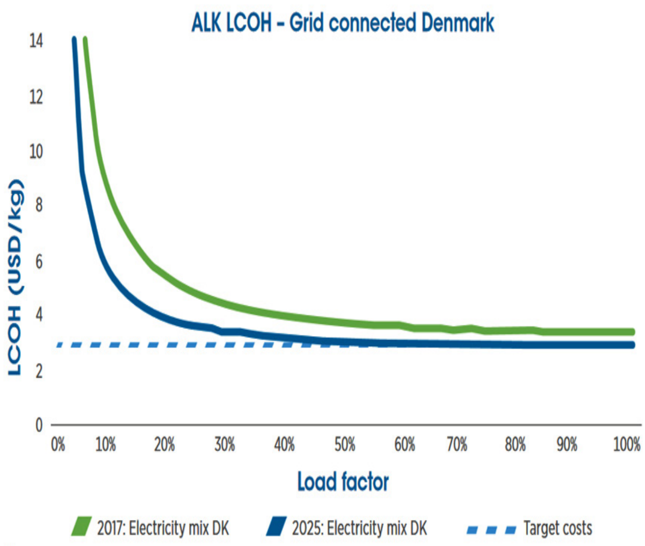


Figure 10: Hydrogen Costs based on Electricity Prices and Electrolyser CAPEX[xxxv]

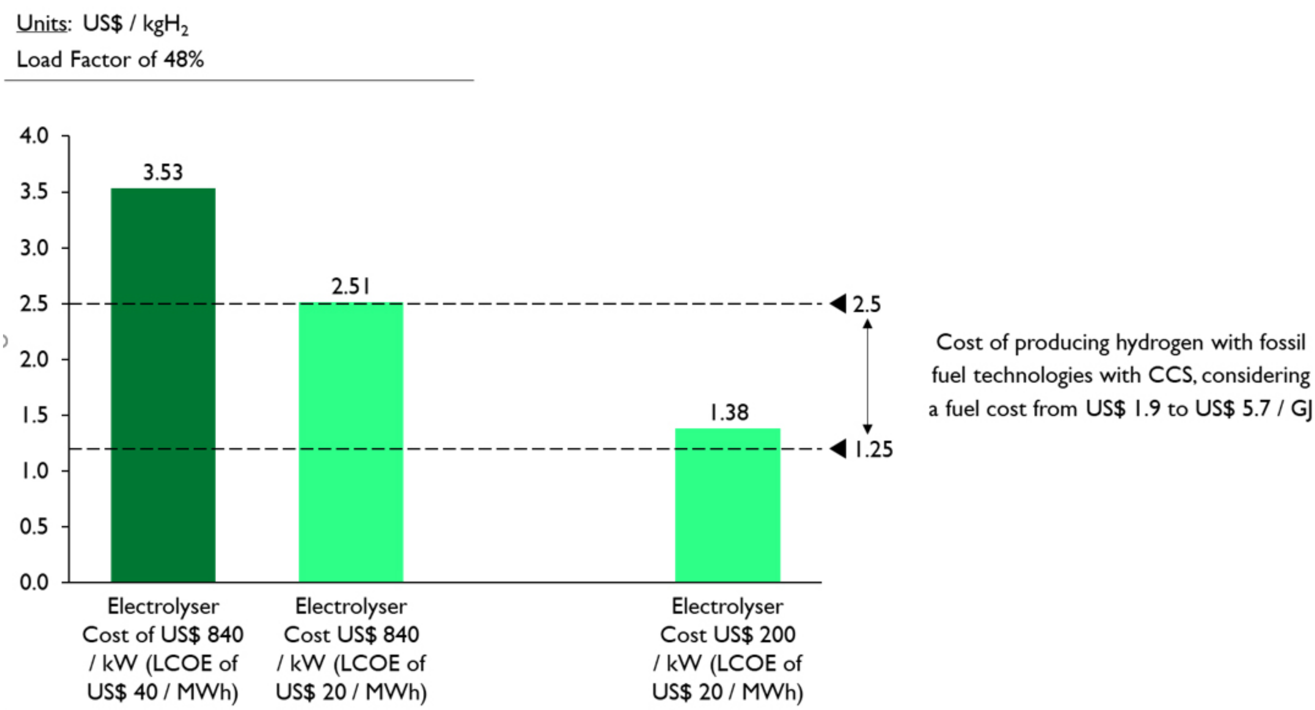
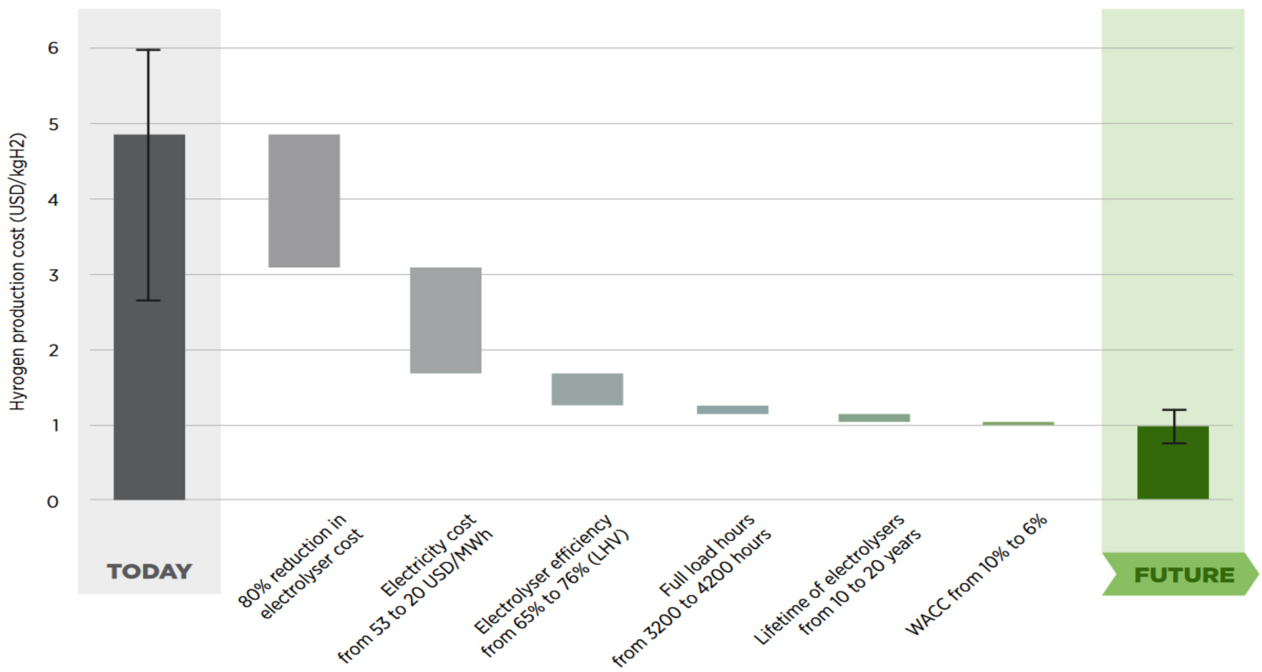


Figure 11: Hydrogen Costs Reduction Potential[xxxvii]



Note: 'Today' captures best and average conditions. 'Average' signifies an investment of USD 770/kilowatt (kW), efficiency of 65% (lower heating value – LHV), an electricity price of USD 53/MWh, full load hours of 3200 (onshore wind), and a weighted average cost of capital (WACC) of 10% (relatively high risk). 'Best' signifies investment of USD 130/kW, efficiency of 76% (LHV), electricity price of USD 20/MWh, full load hours of 4200 (onshore wind), and a WACC of 6% (similar to renewable electricity today).

Based on IRENA analysis

In order for green hydrogen to be cost competitive for various PTX projects, it must be produced for less than ~US$ 2.5 / kg, which is also dependent on whether production is centralised or decentralised, and how the hydrogen will be used (i.e., the PTX pathway)[xxxiv].

Through a combination of low LCOE from renewables, combined with increased efficiency and operating lifetime and a fall in electrolysers CAPEX could lead to a decline in the cost of hydrogen production by 80% in the future, compared to current levels[xxxvi].

And if long-term CAPEX for electrolysers declines faster than the LCOE for renewables, then load factors are likely to play a smaller role in cost reductions, and green hydrogen could become cost competitive with or maybe even cheaper than hydrogen produced from fossil fuels.

While the role of hydrogen in the global energy mix is likely to be modest in the short-term, with further reductions in the cost of producing green hydrogen, it can grow further to make a substantial contribution to ongoing net zero targets and decarbonisation strategies between 2030 – 2050. Therefore, the energy sector and government regulators should coordinate their efforts to make this prospect a reality. This coordination can take place across three different dimensions: across the value chain, borders, and sectors.

In terms of value chain, green hydrogen supply has to expand in parallel with its supporting infrastructure and demand across various PTX pathways. At least during the early stages, when a market has not yet developed, production projects need to be co-developed with an offtaker that can absorb production and reduce the risk of curtailment.

Across various regulatory jurisdiction, the development of an indigenous green hydrogen value chain will benefit from joint partnerships and collaborations across the energy value chain and various end use sectors. This will also enable deployment and leaning by doing, which will drive down costs and also enable the coordination of national programmes.

In terms of sectors, the role of green hydrogen in the energy mix will benefit from combining different applications to stimulate its aggregate demand, which will justify the commercial viability of larger projects, and help achieve economies of scale that benefit production and its supporting infrastructure development.

And in order to develop a commercially viable green hydrogen value chain that supports various PTX pathways, government regulators must use specific policy instruments to encourage green hydrogen production. These include introducing capacity targets, providing financial support in terms of concessional loans and grants, introducing quotas for green hydrogen use, establishing manufacturing targets for electrolyser technologies, and providing tax incentives for various PTG or PTL projects.

Government regulators could introduce capacity targets in tandem with an increase in renewable energy capacity targets in order to ensure renewable electricity demand for green hydrogen production does not displace its use in the electricity mix.

By introducing financial support schemes such as financial grants or concessional loans, government regulators can help mitigate the investment risk associated with these projects, and also contribute to reducing the cost differential with fossil-based hydrogen. In addition, tax incentives could be offered to project developers in order to reduce the impact of high CAPEX on project profitability.

Another way to improve the commercial viability of PTX projects is by introducing blended quotas that mandate the use of green hydrogen for existing uses, or the share of green hydrogen in final energy demand for applications across the industrial, transport, or power sector. Similar to blended targets, government regulators could also introduce manufacturing capacity targets for producing electrolysers to encourage the development of an indigenous hydrogen value chain.

The Gulf Cooperation Council (GCC) countries could also play a leading role in green hydrogen production. The region holds significant advantages in the production of green

hydrogen, due to its abundant, low-cost solar energy. However, green hydrogen entails significant transportation costs to supply export markets in Europe and the Asia-Pacific region.

In order to cater to large export markets, GCC infrastructure developers and energy companies can focus on producing green ammonia as a first step. They can reduce the cost of ammonia production and create economies of scale advantages through technological innovation such as by adapting established processes in the short term, and eventually improving them in the long term to rely exclusively on renewable electricity. Green ammonia can be economically viable in the relatively near future and has a large existing addressable market.

The choice of export markets will also be critical to the commercial viability of green ammonia. Exporters should adopt a long-term view and focus on a relatively small number of markets with sustainable demand due to high consumption and low production potential.

GCC-based energy companies and infrastructure developers should look to establish integrated green hydrogen–ammonia infrastructure hubs that are focused on domestic production and centralised reconversion activities in export destinations in order to achieve the maximum associated cost efficiencies.

In the GCC these hubs could be located near renewable energy projects. They should take advantage of current port and industrial infrastructures. These hubs will attract investment in related industries that will further and accelerate the development of an indigenous hydrogen supply chain, helping to achieve the lowest unit cost throughout.

Further developments of PTX based on hydrogen can then occur into the more commercially and technically-challenging value chains.

CONCLUSIONS

The current interest in PTX is mainly driven by two factors: the huge potential of producing low-cost and low-carbon renewable electricity, and the need for energy and feedstocks in other forms than electricity.

There are important synergies between hydrogen and renewable energy. Hydrogen can support the economics of renewables by providing seasonal balancing and offtake at times of surplus, broaden the reach of renewable electricity, and help decarbonise operations across the industrial, transport, buildings and commercial sector through PTX pathways such as PTG and PTL.

The main challenge for PTX is that advancements in electrolysis technologies are still in their early stage, hydrogen lacks demand as an energy source, and costs are high compared to traditional fossil fuels and to 'blue' hydrogen. These barriers may seem challenging at first but developing a hydrogen-based energy system could improve the economic viability of various PTX pathways.

Early opportunities for PTX technologies are likely to be in small-scale applications, before they transition to commercial and industry-scale, and ultimately to large-scale applications. In the short-term, progress will be gradual with no radical breakthroughs.

Green hydrogen production across various PTX projects is technically viable today and its commercial viability will continue to improve, mainly driven by a decline in electrolyser CAPEX and LCOE from renewables, in addition to an increase in operational efficiency and load factors for electrolysis units.

However, further acceleration of efforts will be critical to ensure hydrogen plays an important role in the energy mix over the coming decades. Therefore, energy companies and infrastructure developers must focus on deployment and learning-by-doing to reduce electrolyser and project costs. Government regulators should consider supporting them by creating legislative frameworks that consist of specific policy instruments to encourage green hydrogen production, which ultimately facilitates a hydrogen-based sector coupling.

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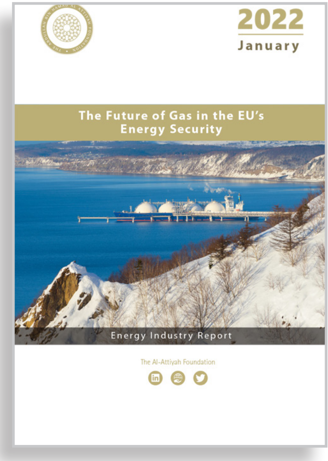

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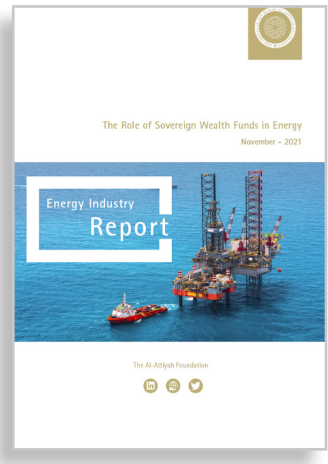

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