



Green Hydrogen and Derivatives Technology Assessment for the Pacific

Draft for Consultation | April 2024

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About the Project

The Efate outcome statement from the Fifth Pacific Regional Energy and Transport Ministers’ Meeting held in Port Vila, Vanuatu in May 2023, recognises the need to consider the potential of green hydrogen and its derivatives in decarbonising the region. This included endorsing the development of a time-bound Pacific regional green hydrogen strategy. Responding to this request, the Australian Government’s Department of Climate Change, Energy, the Environment and Water (DCCEEW) is leading the development of the Pacific Hydrogen Strategy, in partnership with UNSW Sydney, the International Renewable Energy Agency (IRENA) through the SIDS Lighthouses Initiative, the Pacific Community (SPC), and the University of South Pacific (USP).

Pacific Hydrogen Strategy

The Strategy will be built across workshops, stakeholder engagement, and a series of reports. Report A provided a broad overview of the potential opportunity for hydrogen and derivatives. This report (**Report B**) assesses the status of current and emerging H₂ technologies that can be deployed in the Pacific. Report C will focus on mapping the energy resources, land availability, infrastructure, and other feedstocks that would be required to establish the H₂ economy in the PICTs and will investigate the economics of developing the H₂ economy. The overall findings from these reports will then form the basis of a regional hydrogen roadmap. These reports will be accompanied by additional capacity-building resources such as masterclasses/knowledge-sharing platform and an open-source tool for the technoeconomic assessment of potential projects to support the PICTs in becoming H₂-ready. These will be made available through our website (<http://pacifich2strategy.com/>).



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Abbreviations

AE	Alkaline Electrolyser
AEM	Anion Exchange Membrane Electrolyser
bbl	Barrel of oil/diesel equivalent
CO₂	Carbon dioxide
CRI	Commercial Readiness Index
DAC	Direct air capture
EVs	Electric Vehicles
FCEVs	Fuel Cell Electric Vehicles (FCEVs)
FSM	Federated States of Micronesia
GDP	Gross Domestic Product
GJ	Gigajoules
GO	Guarantee of Origin
GW	gigawatt
H₂	Hydrogen
Ha	Hectares
kg	Kilogram
km²	Square kilometres
ktpa	Kilotonnes per annum
kW	Kilowatt
L	Litres
LCA	Life Cycle Assessment
LHV	Lower heating value
MCA	Multi-Criteria Assessment
Mpa	Megapascals
Mtpa	Megatonnes per annum
MW	Megawatt
MWh	Megawatt hours
NH₃	Ammonia
NDCs	Nationally Determined Contributions
P2X	Power to X
KPI	Key Performance Indicators
PICTs	Pacific Island Countries and Territories
PEM	Polymer Membrane Electrolyser
PNG	Papua New Guinea
PV	Photovoltaic – Solar Panels
RMI	Republic of the Marshall Islands
tpd	Tonnes per day
tpa	Tonnes per annum
SAF	Sustainable Aviation Fuel
SOEC	Solid Oxide Electrolyser Cell
STP	Standard temperature and pressure
TJ	Terajoules
TRL	Technology Readiness Level
TWh	Terawatt hours

Executive Summary

Highlights

- Green H₂ and derivatives, including ammonia, methanol, renewable diesel (referring to both bio-diesel and e-diesel), and sustainable aviation fuel (SAF), can play a complementary role to direct electrification and renewable power generation in the PICTs.
- To highlight the applicability of green H₂ and derivatives in the PICTs, this report assesses the status of current and emerging technologies through a detailed literature analysis and market overview of associated value chains.
- A multi-criteria assessment (MCA) approach was applied for an inclusive and systematic comparative analysis of technologies for the production and end-use of green hydrogen and derivatives, based on both qualitative and quantitative metrics.
- The MCA highlights that there is significant potential in the region for renewable fuels derived from waste or purpose-grown biomass, such as bio-methanol, bio-SAF, and bio-diesel. Decentralised production could be beneficial for hydrogen and ammonia.
- SAF, methanol, and renewable diesel emerge as an economically and technically viable opportunity as drop-in replacement fuels for land, maritime, and aviation sectors. Opportunities exist for ammonia and green hydrogen; ammonia may be employed as a maritime fuel, whilst H₂ fuel cells could be used for on-demand power generation and mobility applications.

In the Pacific Islands Countries and Territories (PICTs), the cost of fossil fuels in the key domestic sectors of electricity generation and land, maritime, and aviation transport is estimated at around US \$2.1 billion per year (**Report A**), representing a significant percentage of the region's GDP. The use of fossil fuels also impacts the ambitious energy and climate targets of the PICTs, many of which have set targets of decarbonising their electricity sector by 2030. The potential for green hydrogen and derivatives (including ammonia, methanol, renewable diesel, and sustainable aviation fuel) within the PICTs was outlined in **Report A** and further supported through regional consultations and at COP28.

In these sectors that have proven challenging to abate and electrify across the globe, we have proposed that a hydrogen economy, implemented through regional collaboration between the PICTs, could enable long term energy security and achievement of Nationally Determined Contribution (NDC) targets. However, the domestic generation and use of these fuels requires suitable technologies, that currently range in maturity from demonstration and pilot scale, to commercially mature, at both decentralised and large scales, whilst both national and region-specific challenges, operational conditions, and opportunities must also be considered.

This report assesses the status of current and emerging green H₂ and derivatives technologies (i.e., hydrogen and derivatives that are produced without the emission of greenhouse gases) through a detailed literature analysis and market overview, to highlight their applicability in the context of the PICTs. The assessment entailed a detailed technical and economic overview of production, distribution (storage and transport) and end use of H₂ and derivatives (ammonia, methanol, renewable diesel, and sustainable aviation fuel – SAF). Due to the complementary nature of the biomass and e-based pathways (including the possibility for hybrid pathways), this report also evaluates the biomass-only pathways, acknowledging that the region has undergone significant research in this area to date.

A multi-criteria assessment (MCA) approach was applied for an inclusive and systematic analysis based on qualitative and quantitative metrics. These metrics include technology capability (technology maturity and readiness for adoption in PICTs), economic outlook (economic competitiveness against incumbent fossil fuel technologies), benefits to the PICTs (emission reduction potential and enhanced energy security) and associated risks (potential safety/social considerations and possible burdens on regional natural resources). **Table A** provides the summary of the MCA for the production pathways of green hydrogen (H₂) and its derivatives, focusing on renewable production methods, including both biogenic (i.e., produced using biomass) and e-based (i.e., produced using renewable electricity) methods for producing methanol (bio-methanol and e-methanol), renewable diesel (bio-diesel and e-diesel), and SAF (bio-SAF and e-SAF). The MCA indicates that whilst hydrogen and derivatives production technologies are generally mature, their implementation, particularly in the PICTs, faces challenges in the short to medium term due to high capital costs, water constraints, operational inflexibility, and lack of infrastructure.

The assessment reveals a significant potential for renewable fuels derived from waste or purposefully grown biomass in the region, including bio-methanol as well as bio-SAF and bio-diesel (e.g., hydrotreated esters and fatty acids, alcohol-to-jet, and gasification to Fischer-Tropsch). These can be produced locally and are compatible with existing transportation and end-use infrastructure, offering substantial opportunities for reducing fossil fuel imports. However, the scalability and operational flexibility of biogenic pathways are limited, typically necessitating large-scale (although they can be scaled down), centralised production facilities located near high-footprint biomass resources. The biofuels can then be distributed using existing infrastructure as they can be deployed as a drop-in replacement for fossil fuels without extensive modifications. SAF and sustainable diesel are synthetic replacements of their fossil fuel counterparts and can be easily blended into existing fuels, while methanol can be used as a blend with fuels including diesel, however, would need retrofitting of equipment including engines and storage/transport pathways for a 100% shift to methanol fuel.

TABLE A. PERFORMANCE MATRIX FOR PRODUCTION OF HYDROGEN AND DERIVATIVES IN THE PACIFIC. NOTE: B = BIOGENIC PATHWAY, E = ELECTROLYTIC PATHWAY. SEE SECTIONS 5 AND 6 FOR FURTHER DETAILS.ⁱ

Metric	Hydrogen	Ammonia	Methanol		SAF		Renewable Diesel	
			B	E	B	E	B	E
Technology Maturity (TRL)								
Economic Feasibility								
Energy Efficiency								
Water Efficiency								
Technology Scalability								
Operational Flexibility								
Infrastructure Readiness								

Rank	Guide
High	Best Performing Hydrogen Derivatives
Average	Average Performance
Low	Least Performing Hydrogen Derivatives

It should be noted that the region has invested significant effort into investigating the feasibility of using coconut oil as a diesel replacement, however with various challenges. Biomass has many competing uses in the region and relies on sustainable practices for the generation of renewable fuels. In contrast, e-pathways offer greater scalability and flexibility, allowing for decentralised and distributed production. This approach is particularly suitable for remote areas with access to renewable energy and necessary feedstocks, such as water and waste carbon dioxide (however, carbon capture and direct air capture of CO₂ are also economically challenging, highlighting the importance of biomass). Hybrid pathways (for example, utilising CO₂ from biomass and hydrogen from water electrolysis) are also feasible, however are discussed only briefly in this report for simplicity. While decentralisation may increase production costs due to the loss of economies of scale, they would be valuable in creating self-sustained energy solutions for remote and off-grid areas across the PICTs (enhancing regional energy security, accessibility, and renewable energy penetration). Decentralised production would be especially beneficial for hydrogen and ammonia (which presents more challenges than hydrogen), as it reduces the need for extensive distribution networks, which are currently lacking in the PICTs.

Similarly, **Table B** provides the summary of the MCA for the potential end-use pathways of hydrogen (H₂) and its derivatives in the PICTs. The considered opportunities include the

ⁱ The MCA framework is outlined in **Section 2.2** and further detailed in the **Appendix**. As part of this MCA, the status of green H₂ and derivatives were compared and ranked using the following matrix for the metrics of technology maturity (based on Technology Readiness Level), economic feasibility (based on cost parity against incumbent fuels), energy and water efficiency (based on MWh or litres of water per unit of fuel), technology scalability (based on availability of facilities in different production scales), operational flexibility (based on the ability to be ramped dynamically) and infrastructural readiness (based on a high level qualitative assessment of present infrastructure and its ability to complement H₂ and derivatives production).

use of the derivatives as a means of renewable energy storage and mobility fuels. The enabling end-use technologies are already at an acceptable maturity level (TRL 6 or higher). From a mobility context, SAF, methanol, and renewable diesel derived from biomass emerge as the most economically and technically viable opportunity in the near term (costing approximately 1.3 – 1.7 times higher than the fossil-derived counterparts), in comparison those derived via e-pathways face economic hurdles (costing approximately 3.3 – 4.8 times higher than the fossil-derived counterparts).

Niche opportunities for ammonia use for maritime fuel and fertiliser generation exist. However, these are likely to be the second-stage applications given the low maturity of the technology and lack of demand (e.g., the demand for chemical fertilisers in the PICTs is negligible). Similarly, there would be limited applications for H₂ use in the PICTs (other than as a precursor for other derivatives), whilst the emergence of H₂ fuel cells has opened avenues for use in on-demand power generation and mobility applications. The potential of H₂ offtake for the transport sector may be limited due to the challenges of developing a refuelling network and the competition from battery electric vehicles, as well as methanol and sustainable diesel, that can be used as a drop-in replacement fuel. Instead, a more likely opportunity lies in the development of on-demand H₂ fuel cell power generation systems that can be used to operate critical infrastructure (like remote hospitals, communication networks etc.), that would require a reliable power supply.

TABLE B. PERFORMANCE MATRIX FOR HYDROGEN AND DERIVATIVES END-USE APPLICATIONS IN THE PACIFIC. NOTE: B = BIOGENIC PATHWAY, E = ELECTROLYTIC PATHWAY. SEE SECTIONS 5 AND 6 FOR FURTHER DETAILS.

Metric	Hydrogen		Ammonia			Methanol B E			SAF B E	Renewable Diesel B E	
	Power Storage	Road Fuel	Power Storage	Maritime Fuel	Fertiliser	Power Storage	Road Fuel	Maritime Fuel	Aviation Fuel	Road Fuel	Maritime Fuel
Technology Maturity (TRL)											
Economic Feasibility											
Fossil Displacement Potential											
Emission Reduction Potential											
Infrastructure Readiness											
Scale of Opportunity											

Rank	Guide
High	Best Performing Hydrogen Derivatives
Average	Average Performance
Low	Least Performing Hydrogen Derivatives

Overall, this analysis builds further on the opportunity for H₂ and derivatives in the PICTs, identifying the potential for these technologies to support power generation (especially opportunities requiring reliable generation and energy storage) and mobility applications (through biofuels that can act as an economic drop-in replacement fuel) across the PICTs. Nevertheless, the assessment strengthens the fact that these technologies are not likely to be an envelope solution for decarbonising the PICTs energy network, but can rather play a role as a stopgap solution or in the decarbonisation of hard-to-abate sectors. The next stage of the analysis (**Report C**) will focus on conducting a region-specific economic analysis of these opportunities to establish the most viable scenarios for developing a Pacific Hydrogen Economy.

1. Case for a Pacific H₂ Economy

1.1. Decarbonisation Needs of the Pacific

Analysis from **Report A** highlighted the opportunity for the integration of electrification, energy efficiency measures and green hydrogen and derivatives to decarbonise hard-to-abate sectors, reducing reliance on imported fossil fuels and enabling the development of a sustainable economy. At present, fossil fuels provide around two thirds of all energy needs in the region, exposing the region to non-renewable energy dependency and placing a burden on the economy, with a significant percentage of the region's total GDP (~4-5%) spent on fossil fuels. The threat of climate change to the region continues to garner a collective response amongst the PICTs to lead global action. The ambitious renewable energy targets outlined in their Nationally Determined Contributions demonstrate this continued leadership.¹

These targets require, of course, deep-rooted decarbonisation of the region's energy sector, a task that the PICTs are committed to through their sovereign energy policies, which aim to (i) increase the access to clean-renewably sourced electricity/energy in remote and isolated communities, and (ii) enhance the penetration of clean energy across the entire end-use spectrum. However, whilst progress has been made towards increasing the share of renewable energy in the energy mix, there remain significant challenges in achieving the 100% renewable energy targets that most of the PICTs are pursuing (See **Report A** for the proposed timeline for the achievement of these targets).

A persistent issue is the widespread penetration of fossil fuels in the energy mix and across various end-use sectors. The more populous and industrialised PICTs regions (such as New Caledonia, Fiji, Papua New Guinea (PNG), Solomon Islands, and Samoa) are facing challenges of requiring large-scale and versatile offtake of renewable energy in both power generation as well as industrial and mobility sectors. The more isolated and less populated regions are facing alternative challenges, requiring decentralised and isolated energy systems to fulfil community energy needs.

1.2. The Role of Hydrogen and Derivatives in the Pacific

The energy requirements and commitments of the Pacific provide a promising platform for the application of green hydrogen (H₂) and its derivatives within sectors that are difficult to completely electrify. These fuels can be generated locally by leveraging regionally abundant renewable energy feedstocks (including solar, wind, hydro, and biomass) to achieve regional energy security and a decarbonised energy network.

Report A identified some of these applications, whilst this report analyses them in further depth with consideration of current and emerging technologies. Regionally, H₂ can be generated to support the power sector by enabling long-term energy storage and can be reversibly converted to electricity through fuel cells or combustion within emerging hydrogen gas turbines. H₂ might also potentially be used as a clean energy source for industrial heating, as well as a clean mobility fuel in fuel cell-powered vehicles. Critically, H₂ can be converted into derivatives including methanol, ammonia, renewable diesel, and sustainable aviation fuels (SAF), synthetic alternatives for fossil fuels that can either be used as drop-in fuels or at different scales through technologies that are widely being

deployed around the world. These fuels are key in hard-to-abate sectors (including remote and small scale power generation, and land, maritime, and aviation transport) that cannot be completely electrified, or in locations that cannot make use of conventional renewables technologies (**Table 1**). Note that these end uses will be updated reflecting the findings of this Report, to reflect economic and technical feasibility in the region.

TABLE 1. POTENTIAL HYDROGEN TECHNOLOGIES FOR THE PACIFIC REGION. HYDROGEN AND DERIVATIVES ARE MOST APPLICABLE IN THE MOBILITY SECTOR (LAND, MARITIME, AVIATION, AND HEAVY INDUSTRIAL), ENERGY STORAGE, DISTRIBUTION, AND PRODUCTION.

Application	Hydrogen	Methanol	Ammonia	Renewable Diesel	SAF
Seasonal power storage	✓	✓	✓	✓	
Fuel cell power generation	✓	✓	✓		
Combustion power generation	✓	✓	✓	✓	
Land mobility fuel	✓	✓		✓	
Maritime fuel		✓	✓	✓	
Aviation fuel					✓
Domestic heating and cooking	✓	✓			
Chemical manufacturing	✓	✓	✓		
Sink for CO ₂ sequestration		✓		✓	✓

Preliminary analysis in **Report A** estimates a total annual energy use of the PICTs of ~87 TWh, equivalent to ~2.2 million tonnes per annum (Mtpa) of H₂ on an energy basis. It was determined that there is total fossil fuel use corresponding to ~1.1 Mtpa of H₂ in key domestic sectorsⁱⁱ. This upper bound for the demand of H₂ across the PICTs region is shown in **Table 2**, noting that most of this demand will likely be met by improvements in energy efficiency, electrification of currently non-electricity energy use, and the direct implementation of renewables in the power sector. The major demand regions are expected to be PNG, New Caledonia, and Fiji, which could require over 900 thousand tonnes per annum (ktpa) of H₂ on an energy basis, altogether accounting for ~85% of the regional demand. Samoa, Vanuatu, Tonga, Solomon Islands, and Micronesia could altogether require over 100 ktpa of H₂ (less than 10% of regional demand). The remainder of the demand is shared between the Marshall Islands, Tonga, Kiribati, Tuvalu, Nauru, and the Cook Islands (less than 5% of regional demand).

ⁱⁱ The domestic demand does not include international aviation or fuel bunkering.

TABLE 2. CURRENT ENERGY OUTLOOK AND ROLES IN A POTENTIAL HYDROGEN ECONOMY ⁱⁱⁱ.

PICT	Current energy outlook	Hydrogen potential (ktpa)	Resource potential	Role(s) in a potential hydrogen economy
Fiji	Energy: 7.2 TWh Renewable: 8%	116		<ul style="list-style-type: none"> Potential producer and export hub Average to high solar, wind, biomass, and land availability
Samoa	Energy: 1.6 TWh Renewable: 5%	26		<ul style="list-style-type: none"> Potential producer and export hub Average to high solar, wind, biomass, and land availability
Vanuatu	Energy: 0.9 TWh Renewable: 2%	17		<ul style="list-style-type: none"> Potential producer and export hub Average to high solar, wind, biomass, and land availability
Solomon Islands	Energy: 2.1 TWh Renewable: <1%	30		<ul style="list-style-type: none"> Potential producer and export hub Average to high solar, wind, biomass, and land availability
Papua New Guinea	Energy: 55 TWh Renewable: 10%	480		<ul style="list-style-type: none"> Potential producer and export hub Average to high solar, wind, biomass, and land availability
New Caledonia	Energy: 18 TWh Renewable: 3%	345		<ul style="list-style-type: none"> Potential producer and export hub Average to high solar, wind, biomass, and land availability
Kiribati	Energy: 0.45 TWh Renewable: 1%	6.3		<ul style="list-style-type: none"> Potential net importer
Micronesia	Energy: 0.60 TWh Renewable: 1%	16		<ul style="list-style-type: none"> Potential net importer
Tonga	Energy: 0.64 TWh Renewable: 2%	17		<ul style="list-style-type: none"> Potential net importer
Cook Islands	Energy: 0.35 TWh Renewable: 4%	8.5		<ul style="list-style-type: none"> Potential net importer
Marshall Islands	Energy: 0.35 TWh Renewable: <1%	9.9		<ul style="list-style-type: none"> Potential net importer
Tuvalu	Energy: 0.04 TWh Renewable: 5%	1.1		<ul style="list-style-type: none"> Potential net importer
Nauru	Energy: 0.20 TWh Renewable: <1%	4.5		<ul style="list-style-type: none"> Potential net importer

High
Average
Low

ⁱⁱⁱ See [Report A](#) for further details. The H₂ potential was calculated based on the desktop analysis of potential energy demand sectors across the PICTs and the subsequent H₂ requirement assuming 100% energy conversion. This value is provided as an illustration of the potential application of H₂ and derivatives only. Actual demand values will vary by PICT, by sector, and by derivative employed.

However, there is a discrepancy in resources and potential energy demands across the PICTs, and as such, a wide variety of roles in a potential hydrogen economy could be played by each PICT (**Table 2**). Overall, the PICTs with an average-to-high resource potential could act as large-scale production and centralised export hubs in the region, whilst more isolated and resource-poor PICTs could potentially import regionally produced hydrogen and derivatives from the export hubs in the PICTs. **There is a significant case for a Pacific H₂ economy revolving around the generation of H₂ and its derivatives to fulfil several energy demands, as well as supporting integrated and enhanced regional energy security.**

Such a hydrogen economy requires technologies that can be deployed at suitable scales in the region. Whilst these technologies exist, there is a requirement for deeper analysis of their application, given the unique requirements and circumstances throughout the region. The following section outlines the technology pathways and assessment approach employed to determine the potential of H₂, ammonia, methanol, renewable diesel, and sustainable aviation fuels in the PICTs.

2. Technology Assessment

2.1. Objectives

H₂ and its derivatives have a potential role to play in the PICTs, however, it is important to note that they are not the only option and most likely not the first option to be implemented. Direct electrification of end-use sectors through renewable energy remains a leading opportunity given the current economic and technical barriers of entry for hydrogen and derivatives. From the PICTs perspective, the primary objective is to achieve the highest environmental benefit at the most favourable economics and highest technical compatibility with available resources and infrastructure, which may involve the use of hydrogen in key application areas. The main objective of this report is to consider these goals in establishing a technology-specific assessment of developing a hydrogen economy in the Pacific region, by introducing the commercial and near-term emerging H₂ technologies and assessing their compatibility with the PICT's energy structure, infrastructure, land availability, and policy.

2.2. Assessed Technology Pathways

Herein, we assess the complete H₂ and derivatives value chain, including feedstock procurement, production, storage, distribution, and end-use. **Table 3** highlights the assessed pathways for H₂ and derivatives value chains.

TABLE 3. ASSESSED TECHNOLOGICAL PATHWAYS. NOTE THAT ALL PATHWAYS ARE GREEN / RENEWABLE.

H ₂ Carrier	Feedstock	Production	Storage	Distribution	End Use
Hydrogen	<ul style="list-style-type: none"> Water Renewable power 	<ul style="list-style-type: none"> Renewable Electrolysis 	<ul style="list-style-type: none"> Gaseous H₂ Liquid H₂ 	<ul style="list-style-type: none"> Tube trailers Pipelines 	<ul style="list-style-type: none"> H₂ turbine generation Fuel cells for isolated power generation Energy storage Industrial heating Derivative production
Ammonia	<ul style="list-style-type: none"> Water Renewable power N₂ from air 	<ul style="list-style-type: none"> Renewable electrolysis + Haber Bosch 	<ul style="list-style-type: none"> Liquid NH₃ 	<ul style="list-style-type: none"> Pipeline Ships Truck 	<ul style="list-style-type: none"> Hydrogen carrier Energy storage Fertiliser feedstock Maritime Fuel Power generation
Methanol	<ul style="list-style-type: none"> CO₂, Biomass, or MSW Water Renewable Energy/Bioenergy 	<ul style="list-style-type: none"> Renewable electrolysis + CO/CO₂ hydrogenation to methanol Gasification to syngas + syngas hydrogenation to methanol 	<ul style="list-style-type: none"> Liquid methanol 	<ul style="list-style-type: none"> Pipelines Ships Trucks 	<ul style="list-style-type: none"> Hydrogen carrier Energy storage Maritime Fuel Power generation Feedstock for chemicals Mining operations Diesel/gasoline fuel substitute
Renewable Diesel	<ul style="list-style-type: none"> CO₂ or biomass Water Renewable power 	<ul style="list-style-type: none"> Hydrotreated esters and Fatty Acids Alcohol-to-Jet Gasification and Fischer Tropsch. Power-to-Liquid 	<ul style="list-style-type: none"> Liquid renewable diesel fuel 	<ul style="list-style-type: none"> Pipeline Ships Trucks 	<ul style="list-style-type: none"> Trucks Ships Mining operations Power generation
Sustainable Aviation Fuels	<ul style="list-style-type: none"> CO₂ or biomass Water Renewable power 	<ul style="list-style-type: none"> Hydrotreated esters and fatty Acids Alcohol-to-Jet Gasification and Fischer-Tropsch Power-to-Liquid 	<ul style="list-style-type: none"> Liquid SAF 	<ul style="list-style-type: none"> Pipeline Ships Trucks 	<ul style="list-style-type: none"> Aviation fuel

2.3. Multi-Criteria Assessment

A systematic Multi Criteria Assessment (MCA) approach has been developed to assess the technical and economic outlook of potential H₂ and derivative technologies, and how they can be deployed in the context of the PICTs.^{iv}

The MCA involves comparing and assessing potential technologies across the following categories:

- **Technology Capability:** This includes assessing the technology's maturity (Technological Readiness Level – TRL), infrastructure readiness required to deploy the technology in the PICTs, scalability of the technology, and operational flexibility.
- **Economic Outlook:** This includes assessing the capital and operating requirements of the technology and the potential cost gap with incumbent technology based on a global literature review. A detailed Pacific specific cost benefit analysis will be conducted in [Report C](#).
- **Benefits to the Pacific:** This includes assessing the potential benefits the proposed technology can enable in terms of potential for fossil fuel displacement, local job creation, improved energy security (i.e., the level of renewable energy penetration that can be realised), and climate emissions reductions.
- **Associated Risks:** This includes assessing the risks of deploying the technology, including safety considerations, social concerns, the potential burden on local resources (i.e., land, water, and renewable resources) and future obsolescence (the possibility of the technology being replaced by a competitor).

The MCA framework is then applied to determine the production potential of H₂, ammonia, methanol, renewable diesel, and sustainable aviation fuels in the PICTs. The MCA metrics and scoring criteria for green H₂ and derivatives production technologies are presented in [Table 4](#), and the MCA results are shown in [Table 5](#).

TABLE 4. MCA FRAMEWORK FOR GREEN H₂ AND DERIVATIVES PRODUCTION TECHNOLOGIES.

Metric	Description	Scoring
Technology Maturity	Technology maturity is evaluated based on the technology readiness level (TRL) of the hydrogen and derivatives production technology	1 – TRL 1-4 2 – TRL 5-8 3 – TRL 9
PICTs Infrastructure Readiness	Infrastructure readiness is evaluated based on the availability of existing supporting infrastructure in PICTs required for the production technology, particularly feedstock sourcing (e.g., water, renewable electricity, and carbon source) and storage, as well as product storage and distribution	1 – No necessary supporting infrastructures exist, and significant new infrastructures must be developed 2 – Most necessary supporting infrastructures exist, and the production technology can be implemented safely with several modifications 3 – All necessary supporting infrastructures exist, and the production technology can be implemented safely without any infrastructure modifications

^{iv} The MCA framework and data used for the MCA are further detailed in the [Appendix](#).

Current Economic Feasibility	Current economic feasibility is evaluated based on the current levelised cost (LC) of hydrogen and derivatives production against the fossil counterparts	1 – $LC > 3 \times \text{fossil}$ 2 – $LC = 1.5\text{-}3 \times \text{fossil}$ 3 – $LC < 1.5 \times \text{fossil}$
Energy Efficiency	Energy efficiency is evaluated based on the specific energy consumption (SEC) relative to the lower heating value (LHV) of hydrogen and derivatives	1 – $SEC/LHV > 2$ 2 – $SEC/LHV = 1.25\text{-}2$ 3 – $SEC/LHV < 1.25$
Water Efficiency	Water efficiency is evaluated based on the water consumption (WC) of hydrogen and derivatives against the fossil counterparts	1 – $WC > 2 \times \text{fossil}$ 2 – $WC = 1.25\text{-}2 \times \text{fossil}$ 3 – $WC < 1.25 \times \text{fossil}$
Technology Scalability	Technology scalability is evaluated based on the scale range of the production technology that is commercially available	1 – $\text{Scale} < 1 \text{ GWh/year}$ 2 – $\text{Scale} = 1\text{-}5 \text{ GWh/year}$ 3 – $\text{Scale} > 5 \text{ GWh/year}$
Operation Flexibility	Operation flexibility is evaluated based on the ability of the production system to operate under dynamic conditions of renewable and feedstock input as well as the possibility for automation, enabling standalone operation in remote areas	1 – Non-dynamic 2 – Dynamic but requires special design or measures 3 – Inherently dynamic

TABLE 5. PERFORMANCE MATRIX FOR BIOGENIC PATHWAYS AND ELECTROLYTIC PATHWAYS FOR HYDROGEN AND DERIVATIVES PRODUCTION TECHNOLOGIES. NOTE: B = BIOGENIC PATHWAY, E = ELECTROLYTIC PATHWAY. SEE SECTIONS 5 AND 6 FOR FURTHER DETAILS.

Metric	Hydrogen	Ammonia	Methanol		SAF		Renewable Diesel	
			B	E	B	E	B	E
Technology Maturity								
Current Economic Feasibility								
Energy Efficiency								
Water Efficiency								
Technology Scalability								
Operational Flexibility								
PICTs Infrastructure Readiness								

Rank	Guide
High	Best Performing Hydrogen Derivatives
Average	Average Performance
Low	Least Performing Hydrogen Derivatives

Overall, the MCA reveals that although hydrogen and derivatives production technologies are predominantly quite technically mature, the implementation in general, and in PICTs particularly, may be hampered in the short to medium term by factors such as the current high costs, water constraints, operational flexibility, and the lack of required infrastructure. Nevertheless, there is a high potential for renewable fuels from waste biomass, such as bio-methanol, bio-SAF, and bio-diesel to be feasibly implemented in PICTs, whether they are generated locally or imported. In terms of end uses, these biogenic renewable fuels are also attractive as they are relatively safe to use with the existing infrastructures and offer a high opportunity scale for fossil fuel import savings.

Similarly, an MCA framework is also developed for H₂ and derivatives end-use applications in PICTs. The MCA metrics and scoring criteria for H₂ and derivatives end-use technologies are presented in [Table 6](#), and the MCA results are shown in [Table 7](#).

TABLE 6. MCA FRAMEWORK FOR H2 AND DERIVATIVES END-USE TECHNOLOGIES.

Metric	Description	Scoring
Technology Maturity	Technology maturity is evaluated based on the technology readiness level (TRL) of the hydrogen and derivatives end use applications	1 – TRL 1-4 2 – TRL 5-8 3 – TRL 9
PICTs Infrastructure Readiness	Infrastructure readiness is evaluated based on the availability of existing supporting infrastructures in PICTs required for the end-use applications such as distribution, storage, and engine/appliance compatibility	1 – No distribution and storage infrastructures exist, and significant new engine/appliance must be developed to enable the end-use technology implementation 2 – Distribution and storage infrastructures exist but the product can only be implemented with engine/appliance modification 3 – Distribution and storage infrastructures exist, and the product can be implemented without engine/appliance modification
Current Economic Feasibility	Current economic feasibility is evaluated based on the current delivered cost of hydrogen and derivatives end use applications against the fossil counterparts	1 – Cost > 3x fossil 2 – Cost = 1.5-3x fossil 3 – Cost < 1.5x fossil
Fossil Displacement Potential	Fossil displacement potential is evaluated based on GJ of fossil fuel displaced by GJ of hydrogen and derivatives considering the efficiency of the end use technologies	1 – $GJ_{fossil}/GJ_{hydrogen/derivatives} < 1$ 2 – $GJ_{fossil}/GJ_{hydrogen/derivatives} = 1-1.5$ 3 – $GJ_{fossil}/GJ_{hydrogen/derivatives} > 1.5$
Opportunity Scale in the PICTs	Opportunity scale in PICTs is evaluated based on the potential for the hydrogen and derivatives to replace the applications of fossil counterparts in various sectors such as power storage, road transportation, maritime transportation, and aviation	1 – Scale < 3 TWh 2 – Scale = 3-5 TWh 3 – Scale > 5 TWh
Life Cycle Emission Reduction	Total life cycle emission reduction is evaluated based on how much the total life cycle emission reduction potential compared to the fossil counterparts in reduction percentage	1 – Emission reduction < 50% 2 – Emission reduction = 50-90% 3 – Emission reduction > 90%

TABLE 7. PERFORMANCE MATRIX FOR HYDROGEN AND DERIVATIVES END-USE APPLICATIONS. NOTE: B = BIOGENIC PATHWAY, E = ELECTROLYTIC PATHWAY. SEE SECTIONS 5 AND 6 FOR FURTHER DETAILS.

Metric	Hydrogen		Ammonia			Methanol B E			SAF B E	Renewable Diesel B E	
	Power Storage	Road Fuel	Power Storage	Maritime Fuel	Fertiliser	Power Storage	Road Fuel	Maritime Fuel	Aviation Fuel	Road Fuel	Maritime Fuel
Technology Maturity											
Current Economic Feasibility											
Fossil Displacement Potential											
Life Cycle Emission Reduction											
Picts Infrastructure Readiness											
PICT Opportunity Scale											

Rank	Guide
High	Best Performing Hydrogen Derivatives
Average	Average Performance
Low	Least Performing Hydrogen Derivatives

3. Green Hydrogen

Hydrogen is the building block for derivatives that can decarbonise a wide spectrum of energy needs. The hydrogen value chain analysed in this report is outlined in **Figure 1**. Overall, the hydrogen value chain is relatively well defined, with several end-use opportunities to displace fossil fuels already reaching high levels of technical maturity (i.e., demonstration and commercial projects have been developed globally).

3.1 Hydrogen Production – Renewable Electrolysis

In the context of emerging low-emission H₂ certification schemes, renewable electrolysis refers to hydrogen generation using exclusively renewable electricity-driven electrolysis systems (as detailed *below*). At present, renewable electrolysis provides <1 Mtpa (or <1%) of global H₂ demand.² However the market is primed for a significant jump in scale (**Figure 2**). Provided that the committed projects are developed and in full-scale production by 2030, there would be a 20-fold increase in installed electrolyser capacity, resulting in an additional 11 Mt of renewable electrolysis-based H₂ supply (i.e., 70% of the 16 Mt of new H₂ capacity being developed by 2030).²

A significant increase in installed electrolyser capacities has already been observed in 2023, as the installed capacity of electrolysers has more than doubled since 2022. This significant growth is being observed globally, primarily in the EU, USA, and China, where there is existing large-scale H₂ demand, while the rest of the world, including the Asia-Pacific region (Australia, New Zealand, Japan, Republic of Korea, and Southeast Asian countries) are expected to play a significant role in the coming years due to their decarbonisation aims, as well as ambitions to develop H₂ trade markets. In the PICTs, some H₂ demonstration projects are also underway, as highlighted in **Report A**.

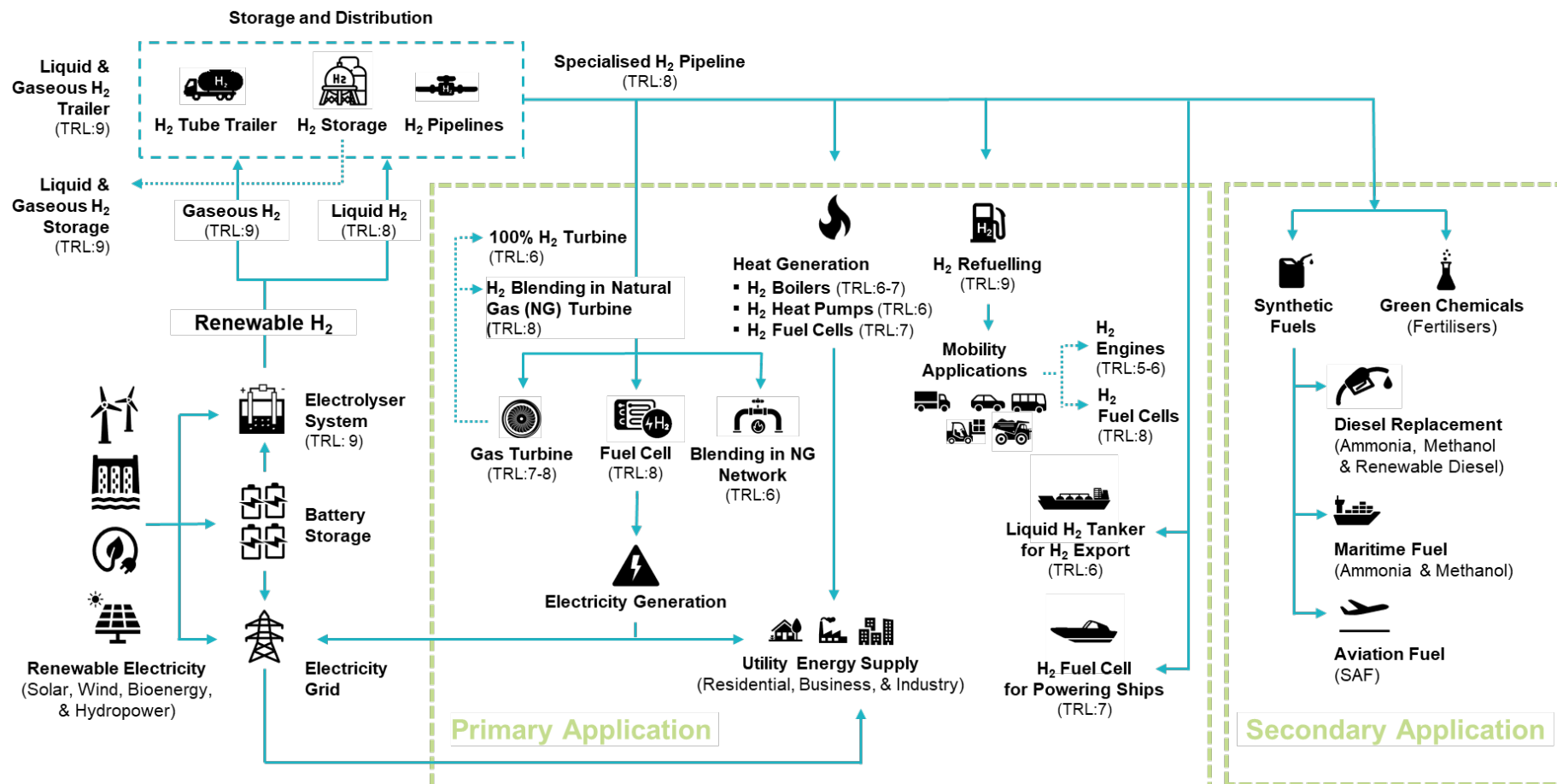
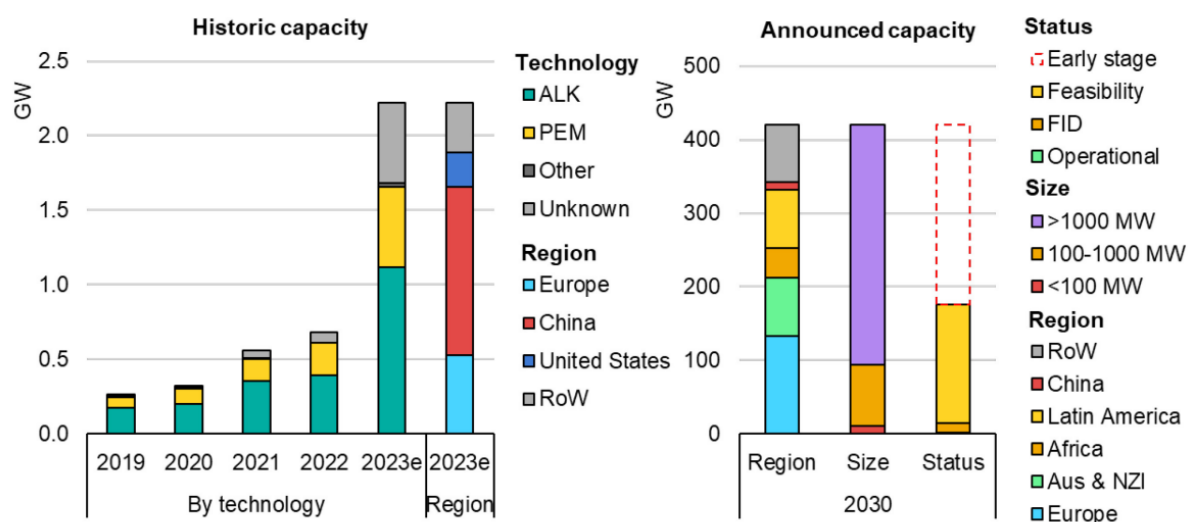


FIGURE 1. THE GREEN HYDROGEN VALUE CHAIN. THE VALUE CHAIN IS DISTRIBUTED INTO PRODUCTION, STORAGE, DISTRIBUTION, AND APPLICATIONS. THE TECHNICAL MATURITY OF THE H₂ TECHNOLOGY USING THE CONVENTIONALLY USED TECHNOLOGY READINESS LEVEL INDEX (BASED ON GLOBAL MARKET OUTLOOK) IS PROVIDED. THE APPLICATIONS ARE DIVIDED INTO (I) PRIMARY APPLICATIONS THAT CAN OFFTAKE PURE H₂ (THESE ARE DISCUSSED IN DETAIL IN THIS SECTION), AND (II) SECONDARY APPLICATIONS THAT INVOLVE CONVERSION INTO DERIVATIVES (THESE ARE DISCUSSED IN THE FOLLOWING SECTIONS).[∨]

[∨] The TRL (Technology Readiness Levels) in **Figure 1** are based on analysis by IEA as part of the Global Hydrogen Review 2023, which are normalised against the TRL index used by ARENA (refer to the **Appendix**).¹



IEA. CC BY 4.0.

Notes: ALK = alkaline electrolyzers; FID = final investment decision and under construction; PEM = proton exchange membrane electrolyzers; RoW = rest of world; Aus & NZI = Australia and New Zealand; 2023e = estimate for 2023 capacity, based on projects planned to start operations in 2023 and that have at least reached FID. "Other" technology refers to solid oxide electrolysis, anion exchange membrane electrolysis or a combination of different technologies. The unit is GW of electrical input. Only projects with a disclosed start year are included.

Source: [IEA Hydrogen Projects](https://www.iea.org/data-and-statistics/data-product/hydrogen-production-and-infrastructure-projects-database). (Database, October 2023 release).

FIGURE 2. STATUS AND OUTLOOK FOR THE GLOBAL ELECTROLYSIS MARKET. FIGURE COURTESY OF IEA² (REPRODUCED FROM THE IEA GLOBAL H₂ REVIEW 2023 UNDER THE TERMS OF THE CC BY 4.0 LICENSE).^{vi}

Electrolysis Technology

Electrolyzers have been developed and employed since the early 19th century. Since then, different types of electrolyzers have been developed to improve efficiency, reduce costs, and adapt to various applications. These include:

- **Alkaline Electrolyte (AE) electrolyzers:** Used since the 1920s, AE electrolyzers are popular for their simplicity and affordability.
- **Proton Exchange Membrane (PEM) electrolyzers:** Developed in the 1960s, PEM electrolyzers are gaining attention for efficiently pairing with intermittent renewable energies. Currently, AE and PEM account for 90% of global electrolyser capacity ([Figure 2](#)).²
- **Anion Exchange Membrane (AEM) electrolyzers:** More recently, AEM systems have been developed that offer greater efficiencies and potentially lower costs than AE and PEM electrolyzers.
- **Solid Oxide Electrolyzers (SOECs):** SOECs have also started to emerge recently due to their ability to be integrated within industrial systems, using excess heat to enhance system efficiency and hydrogen yield (10 to 20% higher than AE and PEM). Overall, AEM and SOEC technologies currently have a relatively small share of the installed electrolyser capacity (<1%)², as the first few commercial AEM and SOEC projects/modules have been deployed in only the last few years making it likely that AE and PEM electrolyzers as the most readily available technology in the near to medium term^{vii}.

^{vi} An up to date list of hydrogen projects is made available by the IEA regularly: <https://www.iea.org/data-and-statistics/data-product/hydrogen-production-and-infrastructure-projects-database>

^{vii} Refer to **Table 8** for a comparative summary of the different classes of electrolyser systems.

Nevertheless, electrolyser technology is an active research space with room for technological breakthroughs, such as the capillary approach-based electrolysers demonstrated in 2022 that despite their low TRL level surpass existing systems in efficiency and expected production cost.²

Status of Electrolyser Technology

Table 8 summarises the current state of the art and future techno-economic benchmarks of electrolyser systems. The salient features of electrolyser systems are summarised below:

Technology Maturity

Overall, AE and PEM electrolysers are the most advanced technology (a TRL of 9), with several established suppliers and large-scale commercial adoption of these systems as highlighted *above*.² In contrast, SOECs and AEM systems are in their early commercialisation stages; SOECs presently account for 1% of the installed electrolyser capacity (**Figure 2**)² and the first large scale (MW capacity) AEM systems have been commercialised in 2023.³

Globally, several established manufacturers of electrolyser systems have emerged as shown in **Figure 3**. For AE systems, Chinese Company Longi, Belgium Company John Cockerill, and German company Thyssenkrupp have some of the largest manufacturing capacities. For PEM systems, USA-based companies ITM Power and Cummins, and German company Siemens have the largest manufacturing capacities.⁴ In contrast, Topsoe (Denmark), Sunfire GmbH (Germany) and Bloomenergy (USA) are developing SOEC systems, whereas Enapter (Germany) are pioneering the development of AEMs.













AE Electrolysers	PEM Electrolysers	SOEC Electrolysers	AEM Electrolysers
   	  	   	

FIGURE 3. COMMERCIAL ELECTROLYSER MANUFACTURERS. NOTE: THIS LIST IS NON-EXHAUSTIVE.

Scale

Commercial electrolyser systems are generally scaled as per their power capacity, from a few kilowatts (kW) to several Megawatts (MW) per electrolyser module (**Table 8**). The larger the scale of the electrolyser system, the higher amounts of renewable energy the electrolyser can absorb and the greater the subsequent hydrogen yield. Therefore, electrolyser systems are usually developed as modular stacks that can integrated to enhance the overall power capacity and yield of the electrolyser system (**Figure 4**).

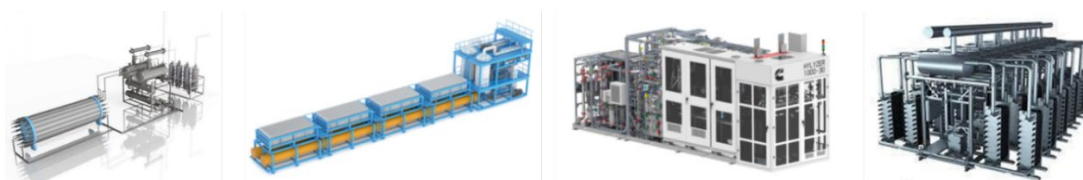


FIGURE 4. SOME COMMERCIAL ELECTROLYSER MODULES. IMAGES COURTESY OF THE MANUFACTURERS (JOHN COCKERILL, THYSSENKRUPP, CUMMINS, AND SIEMENS).

At present, AE and PEM electrolyser systems are being commercialised in the MW scale (1 – 20 MW). For example, Longi and John Cockerill offer a 5 MW AE electrolyser module, while Thyssenkrupp offers 10 MW and 20 MW AE electrolyser modules.^{5,6} ITM offers 2 – 20 MW PEM electrolyser modules, while Cummins offer their HyLYZER PEM electrolyser system in 1 – 20 MW capacity modules. Siemens’s latest PEM module Silyzer 300 is available in a 17.5 MW scale. Electrolyser manufacturers are aiming to develop high-capacity electrolyser modules as they give several advantages, such as reduction of system costs and higher hydrogen yields.⁷ At present, the average scale of electrolyser-based hydrogen projects is in the order of 10 – 100 MW, with projects of up to 1 GW in scale expected by 2030.²

Role of Electrolysers in the PICTs

Given their higher technical maturity, commercial availability and scalability, AE and PEM systems are the most likely to be deployed for widespread H₂ production across the PICTs. In comparison, AEM and SOECs could be deployed in niche applications. For example, given the enhanced reliability and flexibility of AEM systems, they may be deployed for hydrogen refuelling operations and energy storage projects. SOECs might potentially be installed within industrial hubs such as the metallurgical plants in New Caledonia, to leverage waste process heat to generate hydrogen as an additional energy resource (these plants are a major energy consumer in the region).

Efficiency

An important key performance indicator (KPI) for an electrolyser system is energy efficiency, as this is directly correlated with the hydrogen yield. As a common convention, electrolyser efficiency is often quoted as a percentage against the lower heating value of hydrogen (33.33 kWh/kg).⁸ At present, AE and PEM electrolyzers have an efficiency of <70% of lower heating value (LHV) basis, which translates to 13 – 20 kg of H₂ generated per MWh of electricity provided to the electrolyser (**Table 8**). In the long term, these efficiencies are expected to reach >80% of LHV basis, leading to yields of >20 kg H₂ per MWh (**Table 5**). In contrast, SOEC systems have an inherently higher efficiency as they combine both electrical and thermal energy to produce hydrogen. These systems have already achieved a 75 – 85% efficiency of LHV basis (**Table 8**), however, they require additional heat (mainly in the form of steam) to achieve this higher efficiency (~8 – 10 kWh of steam energy per kg of H₂, and the remaining 30 – 40 kWh/kg H₂ supplied by electricity).⁹ Greater efficiency is a crucial factor in reducing hydrogen production costs, leading to increased yields and reduced energy consumption.⁷ Additionally, lower efficiency of electrolyser would necessitate a higher capacity for upstream solar and wind energy to achieve similar yields, resulting in cumulative losses throughout the value chain.

Importance of Electrolyser Scale and Efficiency for the PICTs

An important design consideration for H₂ projects in the PICTs is the scale of electrolysers deployed. Larger electrolysers provide the advantage of higher hydrogen yields and more favourable economies of scale, but have a larger footprint, are more complex to integrate, and have a higher upfront cost.

For example, a current state-of-the-art 100 MW electrolyser system (a typical scale of current projects) with somewhere between 5 to 100 electrolyser units, can generate 18 ktpa of H₂ operating continuously (using grid-based energy, which may not be possible with intermittent renewables), equivalent to a small-scale oil refinery demand. Such an electrolyser would cost somewhere between US \$50 – 140 million, requiring a land area (excluding the power source) of 3,000 – 10,000 m², or around one football field for context^{7,10} to deploy, and 876 GWh of power and 175 GL of water per year (based on just the stoichiometric water requirement of 9 kg H₂O/kg H₂, the actual water requirement can be much higher considering additional requirements such as cooling and purification).

From a PICTs context, up to 10 GWs of electrolyser could be required to meet the estimated 1 Mtpa H₂ demand in key sectors in the PICTs (**Report A**), entailing a significant financing, logistics, and resources challenge. Therefore, targeted small-scale decentralised projects could be a promising strategy for developing the PICT's hydrogen economy. Similarly, high electrolyser efficiency and reliability would be critical to ensure higher hydrogen outputs and effective translation of renewable energy. Energy losses throughout the value chain could impact the competitive advantage of H₂ and derivatives over direct electrification and renewable generation in some sectors, as highlighted *below*.

Electrolyser Lifetime

Across the lifetime of the electrolyser stack, operational stresses due to load cycling, operational conditions, and potential impurities in feedstocks cause a decrease in efficiency, requiring the stacks to be replaced. At present, AE and PEM electrolysers are typically rated for over 60,000 hours of operation (**Table 8**), which would allow projects to be operated for 20 years with 1 or 2 replacement cycles.¹¹ In contrast, SOEC and AEM electrolysers have had a considerably low stack life of 20,000 to 40,000 hours or higher without the need for replacement.¹²

Operating Conditions

Both AE (including AEM) and PEM electrolysers are often referred to as low-temperature electrolyser systems, operating at 40 – 80°C and generating high-purity hydrogen (>99.9% H₂ purity) at a pressure of 30 bar (**Table 8**). These hydrogen specifications align with most end-use applications, as highlighted in later sections. Moreover, all three configurations (AE, PEM, and AEM) are highly flexible and dynamic, offering a wide operational range, and allowing their compatibility with intermittent and variable renewable energy resources. In comparison, SOECs are high-temperature electrolysers operating at 700 – 800°C with a hydrogen output of 1 bar (**Table 8**). This high-temperature operation requirement often sees SOECs being considered in industrial settings where waste process heat can be recycled at a low cost.¹³ In addition, another limitation of SOECs is the low output pressure of 1 – 5 bar,^{14,15} that would require a

downstream compressor (to compete with AE/PEM outputs of 30 bar) adding additional power consumption and costs.¹⁶ SOECs are also relatively rigid and non-flexible, especially cycling between shutdown and startup modes.

Costs

In terms of unit costs, AE and PEM systems are the lowest-cost electrolyser operations on a per kW basis (**Table 8**). At present, these systems generally cost between US \$500 – 1400 per kW, significantly lower than SOEC systems that cost US \$2,000 per kW. AEM systems are yet to be commercialised and manufactured at scale, but there is an expectation that these will cost US \$600 per kW by 2025. The cost of electrolyser systems has seen a recent increase (9% year-on-year increase since 2021) due to inflation and supply chain pressures, causing an increase in project (up to 40%) and production (up to 20%) costs. However, ongoing R&D and achievement of economies of scale are likely to decrease costs by 60 – 70% by 2030.

Operating and Cost Challenges for Deploying Electrolysers in the PICTs

From an operational standpoint in the PICTs, the high humidity, temperature, and corrosive impacts of seawater could be a major challenge for the optimum operation of electrolysers in the region.

The high humidity and temperature are a key concern, as the average temperature in the PICTs across summer remains higher than 30°C with long phases of elevated temperature. Simultaneously the humidity in the region is on average higher than 85% across the year. Altogether, these can impact the cooling systems of the electrolyser which generally, could lead to heat buildup causing the systems to exceed their operational limits i.e. AE and PEM systems generally operate between 70 – 90 °C (**Table 8**). Subsequently causing the system performance to degrade, e.g. electrolyser operation at over 100°C has been found to increase degradation rates by 5 times compared to 60 °C.¹⁷ The tropical condition in the PICTs also often results in a humidity of over 80%, which can further reduce the effect of electrolyser system coolers, making it difficult to maintain operating temperatures. Corrosive impacts can also impact the structural integrity of the electrolyser systems.

Similarly, the remoteness of the region and lack of regional workforce and skills would add to the costs of both the deployment of projects and their operation. Note the above-mentioned electrolyser costs are on an uninstalled basis and represent the ex-factory cost of the electrolyser system only. The additional costs of procuring, installing (engineering, labour, and land), and commissioning need to be considered. Stakeholder engagement with project developers in the PICTs reveals that these costs could be as much as three times higher than reported averages for industrialised countries, due to remoteness and lack of local labour/services.

TABLE 8. OUTLOOK OF TECHNOECONOMIC BENCHMARKS OF ELECTROLYSIS TECHNOLOGY.^{7,18-23}

AE		PEM		AEM		SOEC		
Parameter	Value							
Period ^a	Present KPIs	Future KPIs	Present KPIs	Future KPIs	Present KPIs	Future KPIs	Present KPIs	Future KPIs
TRL ^b	9	9	9	9	5 - 6	9	8	9
CRI ^c	5	6	5	6	1	4	4	5
System Scale	1 – 5 MW	> 10 MW	1 – 5 MW	> 10 MW	5 kW	2 MW	5 kW	200 kW
Efficiency								
▪ SEC ^d (kWh/kg)	50 – 78	< 45	50 – 83	< 45	57 - 69	< 45	40 - 50	< 40
▪ Yield (kg/MWh)	13 - 20	> 20	13 - 20	> 20	14 – 18	> 20	20 - 25	> 25
▪ System Efficiency ^e	43 – 67%	> 70%	40 – 68%	> 80%	48 – 58%	> 75%	75 – 85%	> 85%
▪ Lifetime ^f	60k hrs	100k hrs	50k – 80k hrs	100 – 120k hrs	> 5k hrs	100k hrs	< 20k hrs	80k hrs
Operating Conditions								
▪ Temperature (°C)	70 - 90	> 90	70 - 90	> 90	40 - 60	80	700 - 800	600
▪ Pressure (bar)	<30	> 70	<30	> 70	< 35	> 70	1	> 20
▪ Load Range ^g	15 – 100%	5% - 300%	5 – 120%	5 – 120%	5% - 100%	5% - 200%	30 – 125%	0 – 200%
▪ H ₂ Purity	<99.99%	>99.99%	99.9 – 99.9999%		<99.999%	>99.9999%	99.9%	>99.99999%
▪ Ramp rate ^h	<50 mins	<30 mins	<20 mins	<5 mins	<20 mins	<5 mins	>600 mins	< 300 mins
Costs								
▪ System Cost ⁱ (US \$/kW)	500 – 1,000	<200	700 – 1,400	<200	N/A ^j	<200	> 2,000	<200

Note:

a. Present and Future benchmarks represent the current state of the art and the 2050 targets.

b, c. TRL and CRI represent the Technology Readiness Level and Commercial Readiness Index respectively, these are commonly used indices in literature and industry to represent the technical and commercial maturity of technology. The TRL and CRI ranges used in this study are defined in the [Appendix](#).

d. The SEC represents the specific energy consumption of the electrolyzers in terms of the kWh of electricity used by the system to generate a kg of hydrogen (this includes both the energy consumed by stack and the balance of plant – BoP).

e. System Efficiency is the SEC compared to the lower heating value of hydrogen (33.33 kWh/kg) a common convention used to represent the efficiency of commercial electrolyser.²⁴

f. The lifetime of electrolyser systems is measured in the total number of hours the electrolyser can operate before the stack needs to be replaced due to the impact of degradation due to operational stress that leads to loss of efficiency. Here the lifetime is represented in thousand hours of operation (1,000 hours of operation = 1k hrs).²⁵

g. Load range represents the turndown ratio of the electrolyser compared to its nameplate capacity.

h. Ramp rates represent the time taken in minutes (mins) by the electrolyser to reach its nominal load from a cold start. The lower the time, the faster and more dynamic operation.²⁶

i. Represent the unit cost of the electrolyser system (including stack and balance of plant) as a \$/kW value that can then be correlated with the nameplate capacity of the electrolyser (kW of installed capacity). Note this cost only represents the cost of equipment, the actual capital cost of the installed electrolyser will include additional costs like supply, transport, installation, financing, engineering costs, etc. that would vary on a project-to-project and region-to-region basis.

j. The AEM electrolyser systems are still in their early development/commercialisation scale and therefore their equipment costs are still to be established as they are manufactured at scale. Nevertheless, Enapter anticipates that the cost of their commercial AEM systems can be manufactured for €550 kW⁻¹ or ~US \$600 kW⁻¹ (based on the present conversion rate of 1€ = 1.1 US \$) once the facility automation of the facility is completed and economies of scale are achieved (targeted by 2025).²⁷

Electrolyser Integration with Renewables

The certification of electrolyser hydrogen is receiving considerable attention, given that electricity grids generally have a mix of non-renewable as well as renewable generation technologies. Ensuring that green hydrogen is created from renewable electricity is a vexed issue with questions of temporal and locational matching as well as renewables additionality. In light of the emerging low-impact certification schemes (*elaborated below*), assured low-impact hydrogen requires the electrolyser to be integrated with an exclusive renewable electricity supply. This requirement can expose the system to intermittent and variable operation but ensures that low or ideally no emissions are produced by the generation of the energy used to power the electrolyser.

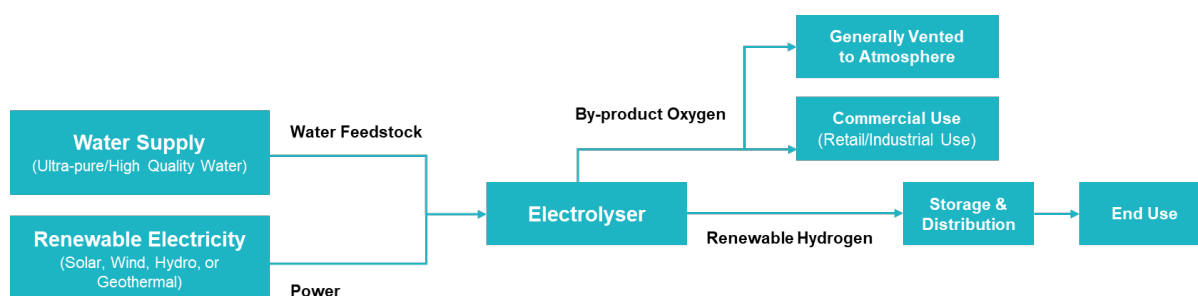


FIGURE 5. THE INTEGRATED RENEWABLE ELECTROLYSIS PATHWAY. HERE THE KEY INPUTS ARE A HIGH-PURITY WATER SUPPLY AND AN EXCLUSIVE RENEWABLE POWER SOURCE FOR THE ELECTROLYSER. THE HYDROGEN GENERATED FROM THE SYSTEM CAN THEN BE STORED AND USED, WHILE THE OXYGEN BY-PRODUCT IS GENERALLY VENTED UNLESS A COMMERCIAL END-USE OPPORTUNITY IS REALISED.

Figure 5 details the renewable electrolysis pathway. The key feedstock inflows and product outflows (**Table 9**) of the electrolyser system are elaborated below:

- **Water Supply:** Stoichiometrically, 9 L of water is required per kg of H₂, however including the water losses and other additional requirements such as cooling water and purification, the total water demand can be up to 30 litres per kg of H₂.²⁸ Additionally, the water source needs to be high purity water (with a low total organic carbon content and a low conductivity of <1 µS/cm) to ensure optimum electrolyser operation.²⁹
- **Renewable Energy Supply:** The renewable energy source can then be supplied through dedicated solar, wind, hydro, biomass, or geothermal powerplant (these resources are available in the PICTs, highlighted in **Report A** and elaborated *below*). Alternatively, the electrolyser can be connected to the renewable power source as a behind-the-meter power purchase agreement (PPA); through which the power utilities add renewable power onto the electrical grid network for distribution and then the project proponent can purchase the power from the grid. However, given the fossil fuel dominant nature of most grids (including the majority of the PICTs) from a certification perspective (*elaborated in the blue box below*), such a PPA would require the use of energy to be temporally matched with the power generation from the renewable power source to ensure exclusive use of renewable power.
- **Hydrogen Production:** Downstream from the electrolyser, the hydrogen generated can then be stored and distributed for different end uses which are elaborated *below* (**Sections 4 – 6**). Commercial electrolyser systems generate H₂

with over 99.9% purity and 30 bar pressure, which makes the H₂ compatible for offtake for almost all end-use cases.

- **Oxygen Production:** In addition, high-purity oxygen is produced as a byproduct of the process (8 kg of O₂ per kg of H₂). Whilst there are several potential end-use opportunities for the oxygen in the PICTs (e.g., for medical use, wastewater treatment, and gasification of biomass), it is unlikely that the oxygen can be economically captured, stored, and transported for use in most cases, and thus is likely to be vented.

TABLE 9. INFLOWS AND OUTFLOWS OF RENEWABLE ELECTROLYSIS SYSTEMS.

Feedstock Requirement	
Energy Consumption (including electrolyser stack and balance of plant)	<ul style="list-style-type: none"> ▪ 50 – 80 KWh/kg
Water	<ul style="list-style-type: none"> ▪ 9 L/kg of H₂ (stoichiometrically) ▪ Up to 30 L/kg of H₂ (including cooling water, purification etc.)
Product Specification	
Hydrogen	<ul style="list-style-type: none"> ▪ Up to 30 bar pressure ▪ >99.9% Purity of H₂ (trace amounts of water and O₂)
Oxygen	<ul style="list-style-type: none"> ▪ 8 kg of O₂ /kg of H₂ (stoichiometrically) ▪ >99.9% purity of O₂ (trace amounts of water and H₂)

Suitability of the PICTs Energy Grids for Electrolyser Deployment

From a PICTs context, the electricity supply is currently highly dependent on fossil fuel energy generation capacity. Analysis from **Report A** highlighted that the average energy supply across the assessed PICTs is 82% fossil fuel with a 15% share of biomass energy and only 3% from renewables. In addition, the electricity supply network across the PICTs is not widely distributed, mostly confined to major towns and industrial hubs, and is challenged by the island nature of the PICTs. The use of the fossil fuel-dominated electricity grid for electrolysis will be a global compliance concern considering emerging H₂ certification schemes (see *below*).

Moreover, as the share of solar and wind energy is increased in the grid, hydrogen energy systems can play a complementary role. The high share of intermittent and variable solar and wind-based electricity adds complexity and stability issues due to the potential temporal mismatch between demand and supply. That can lead to cascading impacts like renewables curtailment and, in extreme conditions, even energy blackouts which would have a significant impact on the PICTs economy. In turn, hydrogen-based power systems can be established to maintain solar and wind energy variations, as they can store excess renewable energy (conversion to H₂ using electrolysis) and on-demand conversion to electricity (via fuel cells or gas turbines as elaborated *below*). Moreover, H₂ can add additional benefits including (i) transfer of renewable energy to hard-to-abate sectors via

H₂ energy carriers and (ii) long-term energy storage, which could complement the PICTs energy system from supply disruption by providing backup power solutions during supply outages from technical failures, extended periods of low renewables or disruptions due to cyclones etc. that are common in the region.

Nevertheless, the key advantage of electrolyser systems is their scalable modularity and the ability to be operated as a decentralised system when integrated with solar and wind farms. Therefore, these systems can be used for robust power generation in remote off-grid locations across the PICTs.

Low Impact H₂ Certification and Incentives Schemes

Considering emerging needs for a low-emission H₂ market, global certification schemes are being introduced that define and set benchmarks for low-emission H₂ production.³⁰ Generally, these are based on a Guarantee of Origin (GO), under which H₂ is renewable (or green) if the power source for electrolysis is exclusively renewable-based. Certification schemes informed by policies such as the EU's REDII directive and CertifHy have built further on these GO schemes with additional conditions including geospatial and temporal matching of renewable energy production and subsequent consumption for H₂ production.³¹ Australia is also working on developing a GO scheme for both renewable energy generation and hydrogen, that is expected to be formalised by 2024, and can be extended to hydrogen derivatives.³² There are also ongoing efforts for globally applicable certification standards, with the International Partnership on Hydrogen Fuel Cells in the Economy (IPHE) introducing a framework for assessing emissions across the H₂ value chain.³³ The Green Hydrogen Organisation has introduced a global industry lead standard for green H₂ and ammonia.³⁴ The ISO at COP28 introduced the ISO standard TS 19870, which specifies methodologies to determine the carbon footprint of hydrogen based on the ISO 14067 LCA framework.³⁵

The USA and Japan have also set emission thresholds (kg CO₂/kg H₂) for low-emission hydrogen.^{36,37} Under the terms of the USA's IRA subsidy, the highest production tax credit is available for ultra-low emission production (<0.45 kg CO₂/kg H₂), which would effectively reduce the cost of generation by half.³⁷

The adoption of similar incentives and certification schemes provides another opportunity for the PICTs to become compliant with the global H₂ economy. In the context of this report, it is assumed that low-impact H₂ is primarily generated through electrolysis powered by solar, wind, geothermal, biomass and hydropower-based electricity, or via the biomass gasification pathway that is detailed later.

Economics of Renewable Electrolysis

A key barrier to entry for renewable electrolysis is the economics of the process. The cost-effectiveness of electrolysis is highly dependent on several factors. Encompassing these factors, the cost of hydrogen projects is generally represented as a levelised cost of hydrogen in dollars per kg (A\$/kg of H₂) which is effectively the net present value of the capital and operating expenses against the lifetime production of hydrogen. A key benchmark for this levelised cost is often established as a US\$1 – 2 per kg of H₂, at which cost electrolysis-based hydrogen is expected to be viable for offtake across the energy spectrum.³⁸ Until recently, this target has largely been elusive, however with the ongoing

R&D into electrolyser technology yielding process and cost improvements, achievement of economies of scale in both manufacturing and project development, and further complemented with the decrease in renewable energy costs from solar and wind, there is a growing expectation that these costs can start falling below US \$2/kg by the end of the decade.^{2,7}

Altogether, there is an expectation that the electrolyser capital costs of US \$500/kW and energy prices of US\$ 30/MWh would be required to achieve these targets. The cost of electrolyser systems (especially AE and PEM systems) is largely on the required trend, which despite a recent increase in costs due to inflationary and supply chain impacts is likely to reduce cost by up to four times (**Figure 6A**). Similarly, solar and wind energy projects are already the least cost options for new capacity globally; a recent analysis by IRENA suggests that the global average solar PV and wind-based electricity prices are in the order of US \$33/MWh to US \$80/MWh respectively.³⁹ These values would yield subsequent hydrogen production costs in the order of US \$4 – 6/kg and higher (**Figure 6B**). However, as energy prices fall below US \$30/MWh, the hydrogen costs will be in the order of US \$1 – 2/kg (**Figure 6B**). Costs will of course be region dependent including the quality of renewable resources, supply chains and infrastructure.

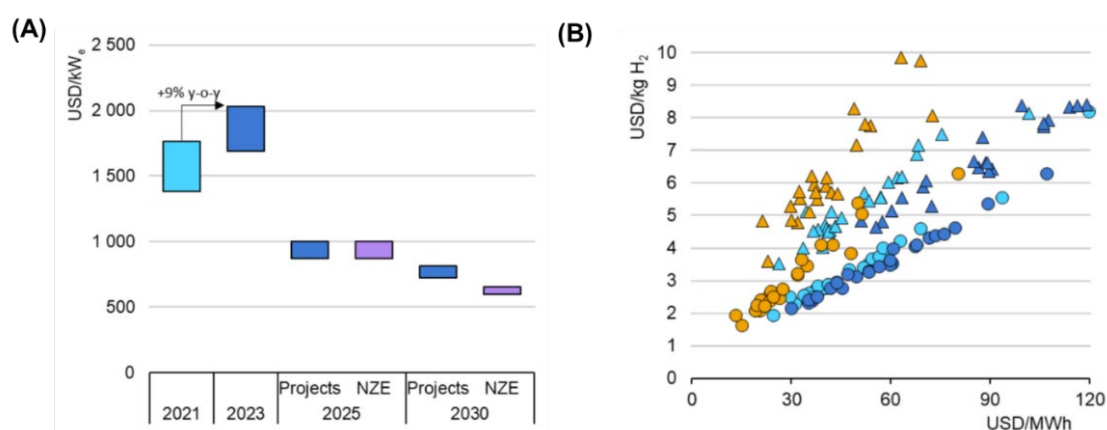


FIGURE 6. OUTLOOK OF ELECTROLYSER COSTS AND SUBSEQUENT HYDROGEN COSTS. FIGURE A REPRESENTS THE RECENT AND FUTURE ESTIMATES FOR ELECTROLYSER SYSTEM COSTS. **FIGURE B** REPRESENTS THE LEVELISED COST OF HYDROGEN AS A FUNCTION OF ELECTRICITY PRICES. THE TRIANGLES (Δ) AND CIRCLES (O) REPRESENT THE COSTS IN 2020 AND ESTIMATED COSTS FOR 2030. THE GOLDEN SHADE REPRESENTS THE COST OF SOLAR PV (CAPACITY FACTOR OF 28%). THE LIGHT AND DARK BLUE REPRESENT THE COST FOR ONSHORE WIND (CAPACITY FACTOR OF 40%) AND OFFSHORE WIND (CAPACITY FACTOR OF 56%). THE H_2 COST WAS CALCULATED ASSUMING A 6% COST OF CAPITAL. IMAGE REPRODUCED FROM THE IEA GLOBAL H_2 REVIEW 2023 UNDER THE TERMS OF THE CC BY 4.0 LICENSE.²

Additionally, the intermittency of solar and wind projects is a key limiting factor. Variable and intermittent operation will lead to lower than optimum operability of the electrolyser systems, resulting in lower hydrogen generation and capacity efficiencies.¹¹ At present, solar and wind energy projects have a capacity factor of 30 – 50%, however, there are opportunities for enhancing the subsequent electrolyser operability by oversizing or creating a hybrid and battery/grid-assisted powerplant. Nevertheless, these opportunities require additional investments that would have to be traded off with the benefit of higher hydrogen yields.⁴⁰

Overall, the deployment of electrolyzers will create new loads for greater renewable energy expansion and penetration, assisting in the achievement of renewable energy targets and NDCs in the PICTs. However, the integration of electrolyzers at scale is limited by factors such as land availability to host large-scale solar and wind farms. Additionally, a key challenge, as highlighted above, is the procurement of equipment, resources, and labour into the region, which would cause the capital costs to increase significantly. This will add risk to investment, which will have to be acknowledged and included in the economics. Nevertheless, the risks are manageable through balanced and targeted investments (potentially leveraging lower financing costs). These factors will be considered in the analysis undertaken in **Report C**.

In addition, there are alternative pathways for hydrogen generation that may become cost-effective in the long term. For example, methane pyrolysis (the thermal decomposition of methane to form hydrogen and carbon) is more energetically economical than electrolysis, theoretically requiring only 37.5 kJ per mol H₂, however, this technology is in the research stage and requires a source of natural gas, limiting its application in the PICTs.⁴¹

Hydrogen can also be produced via biomass, however, there may be heavy competition for land in the PICTs, and for biomass products as a food or export source, as well as for the synthesis of hydrogen derivatives such as SAF. Alternative hydrogen generation pathways include photocatalytic, solar thermal, solar electric, and nuclear, however, these technologies are at a low TRL or are likely unsuitable for the PICTs due to land or resource availability.⁴²

Note: Report C will conduct an in-depth techno-economic analysis of hydrogen projects in the PICTS. Complementing this report, a website-based hydrogen and derivative project costing tool will be made available.

3.1. Hydrogen Storage and Distribution Technology

Once the hydrogen is generated, it can be stored and distributed as a gas or a liquid. Hydrogen as a gas has the significant advantage of having the highest energy content per unit – gravimetric energy density (kWh/MJ per kg - **Figure 7**). On a mass basis, hydrogen has a three times higher energy density compared to gasoline/diesel. However, for storage and distribution, a critical challenge is the low density of gaseous hydrogen, which results in larger volumes of energy storage required to store competitive amounts of energy compared to fossil fuels (hydrogen needs three times more storage space as a gas, as seen in **Figure 7**). Therefore, bulk volumes of hydrogen are generally required to be stored as a liquid. The liquefaction of hydrogen requires significant energy to reduce the temperature to -253°C (roughly 10% of the energy stored in hydrogen).

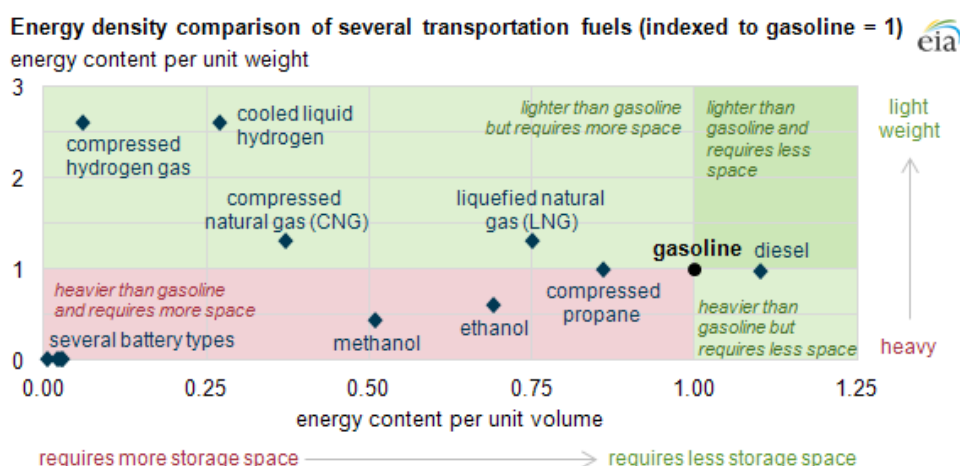


FIGURE 7. ENERGY CONTENT OF HYDROGEN AGAINST COMPETING FOSSIL FUELS. HERE THE Y-AXIS REPRESENTS THE GRAVIMETRIC ENERGY DENSITY AGAINST THE VOLUMETRIC ENERGY DENSITY (X-AXIS). HIGHER VOLUMETRIC ENERGY DENSITY MEANS LOWER SPACE REQUIREMENTS FOR STORAGE. H₂ HAS A HIGHER GRAVIMETRIC ENERGY DENSITY THAN COMPETING FOSSIL FUELS BUT HAS A SIGNIFICANTLY VOLUMETRIC ENERGY DENSITY THAT MEANS 3 – 4 TIMES THE STORAGE SPACE REQUIRED TO STORE SIMILAR AMOUNTS OF ENERGY AS FOSSIL FUELS. IMAGE COURTESY OF US EIA.⁴³

H₂ Storage Technology

Gaseous Hydrogen

As a gas, H₂ is generally stored under pressure at 300 – 700 bar in specially designed metallic or composite vessels. Storage at higher pressure conditions increases the H₂ density (mass per unit volume), allowing larger amounts of H₂ to be stored per volume. The density of H₂ increases to 20 kg/m³ at 300 bar (at room temperature) and 40 – 70 kg/m³ at 700 – 2000 bar, compared to the 0.08 kg/m³ at standard temperature and pressure (STP).⁴⁴ The scale of storage depends on the end use, e.g., storage tanks for fuel cell vehicle applications that have 5 kg (light duty) –70 kg (heavy duty) of H₂ storage at 300 – 700 bar respectively and up to 1 tonne of hydrogen stored for H₂ storage onboard gaseous H₂ tube trailers.






Gaseous H₂ Storage Compression Requirements

Increasing the H₂ pressure requires it to be compressed; several types of mechanical and non-mechanical compressors have been developed for H₂. A key challenge for hydrogen compression is its higher compressibility factor compared to other gaseous, which results in higher power requirements. This power requirement can range between 1.7 – 6.4 kWh/kg of H₂, depending on the inlet, outlet pressure and compression efficiencies.⁴⁵

Overall, the additional cost of compression is expected to add US \$1 – 2/kg to the production costs.⁴⁶

The storage vessels used for H₂ storage are classified based on their types and composition. At present, five different types of H₂ storage vessels are commercially being used. The key features of these storage types are provided in **Table 10**.

TABLE 10. OVERVIEW OF COMMERCIAL GASEOUS HYDROGEN STORAGE VESSELS.^{47,48}

Type I	Type II	Type III	Type IV	Type V
				
<ul style="list-style-type: none"> Type I vessels are all metallic in make (usually steel). These vessels are the heaviest and are usually used for stationary applications. Can store hydrogen at pressures of 200 – 300 bar (~15 g/L of H₂) These are the most used types of storage in the market. These cylinders cost ~US \$83/kg 	<ul style="list-style-type: none"> Type II vessels have a metallic liner (steel or aluminium) with a composite layer. The internal pressures are shared between the metal and composite layers. These vessels are lighter than Type I and are usually used for stationary applications because of challenges of low storage densities, weight, and embrittlement issues. Can store hydrogen at pressures of 100 – 500 bar (~20 g/L of H₂) These cylinders cost ~US \$86/kg. 	<ul style="list-style-type: none"> Type III vessels have a metallic liner (steel or aluminium) with a composite layer. The key difference with Type II is that here the composite layer cocoons the metallic layer and provides higher stress-bearing capacity. These vessels are lighter than Type I and Type II and are used for mobility applications. Can store hydrogen at pressures of 300 – 700 bar (~20 – 40 g/L of H₂). These cylinders cost ~US \$700/kg. 	<ul style="list-style-type: none"> Type IV vessels have a metallic liner (steel or aluminium) with a double layering of the plastic liner and composite layer. These vessels are lighter than Types I-III and can operate at higher pressures. Can store hydrogen at pressures of around 700 – 900 bar (~40 g/L of H₂). These cylinders cost ~US \$650/kg. 	<ul style="list-style-type: none"> Type V vessels are all-composite, liner-less tanks. They can store hydrogen at around 1000 bar. Storage of hydrogen in Type V vessels can be challenging due to the leakage of hydrogen.

Liquid Hydrogen Storage

In comparison, liquid hydrogen (LH₂) needs to be stored under cryogenic conditions (-253°C at atmospheric pressure). This is particularly useful, as the density of hydrogen increases several-fold to 71 kg/m³ (~1,000 times denser than H₂ gas at STP). Once liquefied, the LH₂ can be stored at a significant scale. Generally, LH₂ vessels have a capacity of 50,000 – 60,000 L per tank, which can store up to 4 – 5 tonnes of H₂.⁴⁹ NASA currently has the largest LH₂ tank, as part of its operation in Florida, with a capacity of 270 tonnes of LH₂ (**Figure 8**). Even higher capacity LH₂ storage tanks in the order of 2.8 – 3 kton are also being developed and manufactured in anticipation of the emerging H₂ economy.⁵⁰



FIGURE 8. LIQUID H₂ IS STORED IN SPHERICAL CRYOGENIC TANKS. IMAGE COURTESY OF NASA.

Liquid H₂ Storage Challenges

A critical limitation of liquid hydrogen storage is the need for liquefaction, which is both costly and highly energy intensive. The current state-of-the-art liquefaction units consume between 12 – 15 kWh/kg of LH₂, which is 35 – 45% of the lower heating value of H₂ (i.e., the useable energy in a kg of H₂ can deliver).⁵¹ This contributes significantly to liquefaction costs, estimated to be between US \$2.75 – 3/kg of LH₂, with an additional cost of up to US \$1/kg for loading and distribution. Including the production costs of hydrogen (US \$4 – 6/kg), the total delivery cost of LH₂ could be as high as US \$7 – 10/kg.^{51,52}

Therefore, LH₂ has mostly been used for specialised applications, limiting its large-scale adoption. At present, the global installed capacity for liquefaction units is estimated to be 350 tpd (with the largest unit having a capacity of 32 tpd).⁵¹ Moreover, the storage tanks must be pressurised (8 – 10 bar) and kept at cryogenic conditions to avoid boil-off and loss of hydrogen as vapour.⁵³ Boil-off rates in the order of 1 – 5 % per day have been established.⁵⁴ New re-liquefaction and refrigeration technologies are being developed to minimise this boil-off (with a potential to reach zero boil-off).⁵⁴

Hydrogen can also be reversibly stored both physically and chemically in various media to enhance its storage density. These include metal hydrides and chemical carriers; however, these are low TRL and unlikely to be appropriate for the Pacific at scale for some time.

Metal Hydride Carriers

The absorption of hydrogen in specially designed metal hydrides is one such pathway. These metal hydrides have specially designed and selected metals that have porous and active surfaces, into which hydrogen can be injected under pressure causing it to either be absorbed or chemically bonded to the metal.⁵⁵ The storage of the hydrogen is reversible, addition of excess heat and reduction in pressure causes the dissociation of the hydrogen from the metal as a gas, that can be recaptured and used. Magnesium hydrides, titanium alloys with iron and magnesium, and other complex hydrides such as lithium and sodium alloys with aluminium have been developed, that are both lightweight and have higher volumetric energy densities than liquid and gaseous hydrogen storage.⁵⁶ While these materials are promising, they are yet to be demonstrated at scale and are proving costly and difficult to develop.⁵⁶

Chemical Carriers

In addition, methanol, ammonia, and liquid organic hydrogen carriers (LOHCs) are emerging as potential hydrogen carriers. Hydrogen can be converted into these chemicals through existing chemical processes, *detailed below*, which due to their inherent chemistry are easier to store and transport (for example, they are liquids, or are of higher density at STP). These carriers can then directly be used as fuel or commodities, or the hydrogen can be recovered through thermo-electric or chemical decomposition of the energy carriers. From a PICTs perspective, these storage pathways would be likely applicable for bulk storage and transport of hydrogen (intra/inter-regional export).

- **Ammonia:** Ammonia (NH₃) is being viewed as a storage/carrier medium for H₂ as it is ~18 wt. % hydrogen, with a higher volumetric energy density (~5 times higher

than H₂ at STP), and it can be stored at relatively lower pressure with the added advantage of low flammability and explosivity. Moreover, ammonia can be further liquefied at relatively milder conditions; -33°C at standard pressure and at 10 bar at room temperature, to have ~11 kg of H₂ per 100 L (1.5 times that of liquid hydrogen).⁵⁷ The ammonia can then be reconverted to hydrogen through thermochemical and electrolysis processes; however, these are still at low TRL (except for the thermo-catalytic process through nickel-based catalysts, that have reached TRL of 9 and occurs at 400 – 600 °C, with up to 90% conversion efficiencies).⁵⁸

- **Methanol:** Methanol (CH₃OH) is also being considered as an energy carrier as it is a liquid at ambient temperature and pressure, with a volumetric energy density of 15.8 MJ/L (higher than both gaseous and liquid H₂ and ammonia) and a hydrogen content of 9.9 kg H₂ per 100 L.⁵⁹
- **Liquid Organic Hydrogen Carriers (LOHCs):** Similarly, specialised LOHCs like toluene are expected to be used in the long run at scale to transport bulk amounts of hydrogen. These materials can absorb hydrogen chemically, e.g., one mole of toluene (C₇H₈) can store 3 moles (6 kg of H₂) to generate a mole of methylcyclohexane (MCH, C₇H₁₄); MCH can then be dehydrogenated to retrieve the three moles of H₂.⁶⁰

Nevertheless, the need to reconvert these carriers significantly to H₂ for use contributes significantly to the total delivered cost of hydrogen. Estimates indicate that the cost of reconvert ammonia, methanol, and LOHC (toluene) to H₂ could be as high as US \$1/kg, US \$1.06/kg, and US \$1.22/kg of H₂, respectively. Note, these estimates do not include the additional cost of generating the carriers, which altogether would likely make these carriers more expensive than gaseous hydrogen storage.⁶¹

H₂ Transport Technology

The distribution of H₂ is generally conducted through either specialised pipelines or through storage vessels that can be loaded onto trucks, railway lines, or ships. Given the lack of infrastructure to develop pipelines and a shipping network, tube trailer-based transport is likely the way forward for the PICTs.

H₂ is transported using gaseous or liquid hydrogen tube trailers (**Figure 9**). Gaseous H₂ tube trailers (**Figure 9A**) are developed around individual storage tubes that store H₂ at 180 bar and higher, giving them the ability to store and transport 0.3 – 1 tonne of H₂.⁶² In comparison, liquid H₂ tube trailers (**Figure 9B**) store liquified H₂ under cryogenic conditions (-253 °C at 1 – 2 bar). Generally, such trailers can store 45,000 – 65,000 litres of liquid H₂,⁶³ which translates to 3 – 5 tonnes of H₂ (given the density of liquid H₂ of 0.07 kg/litres of H₂). Liquid tube trailers have a boil-off concern during loading, transport, and offloading, together these are estimated to be 0.3 – 0.6% per day.⁶⁴

The development of an H₂ distribution network would need complementary infrastructure, such as compression/liquefaction units, storage capacity, and unloading/offloading terminals. In addition, there will be regulatory concerns for safety, such as limits on storage capacity per tube trailer. For example, in Australia, tube trailers can transport a maximum of 1 tonne per trailer.⁶⁵ Similar standards would need to be developed or adopted in the Pacific to ensure compliant and safe deployment and operation of H₂ transport networks.

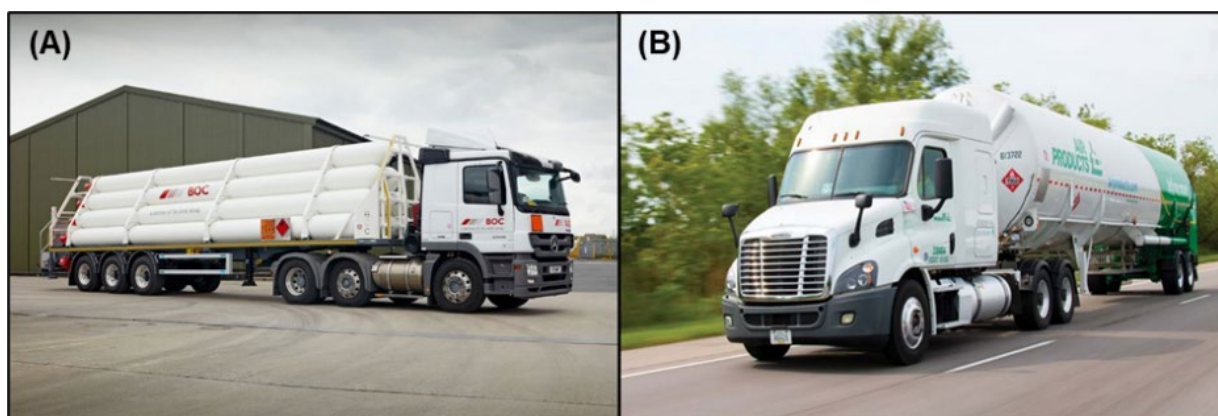
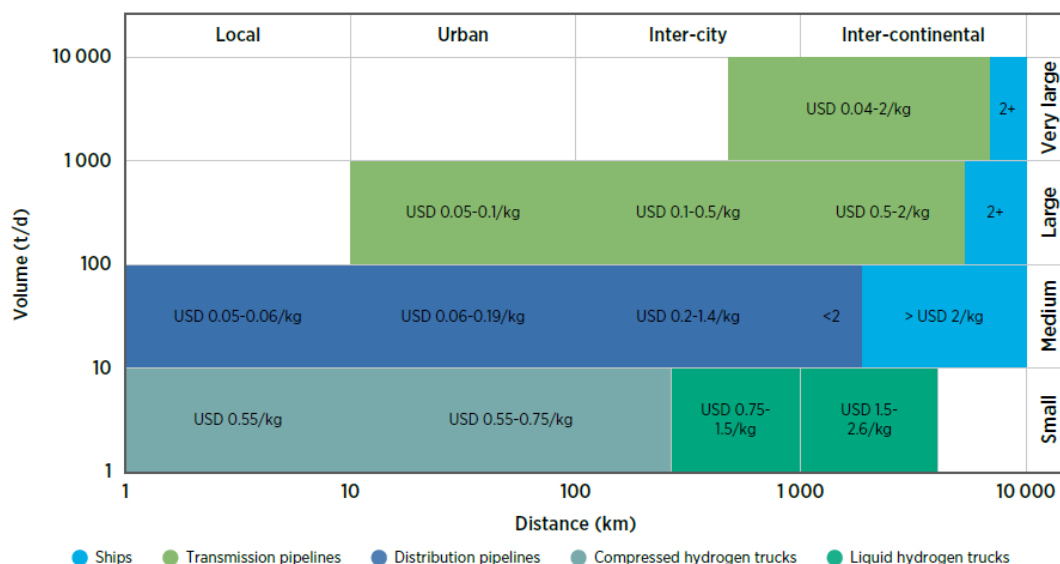


FIGURE 9. TUBE TRAILERS FOR HYDROGEN DISTRIBUTION. **FIGURE A** SHOWS A GASEOUS H₂ TUBE TRAILER, THAT STORES PRESSURISED H₂ GAS IN INDIVIDUAL STEEL TUBES. **FIGURE B** SHOWS A LIQUID H₂ TUBE TRAILER, THAT STORES LIQUID HYDROGEN UNDER CRYOGENIC CONDITIONS. IMAGES COURTESY OF BOC AND AIR PRODUCTS LIMITED.

The suitable transport medium for hydrogen within the PICTs will depend on a trade-off between the scale (mass of hydrogen transported – tpd), the range (distance of distribution), and the eventual cost (US \$/kg) as shown in **Figure 10**. Tube trailers are most suitable for a scale of <10 tpd for up to 5,000 km. Gas tube trailers are likely for a shorter range (up to 500 km) at a cost of US \$0.55 – 0.75/kg, whereas liquid tube trailers are for a higher range (500 – 5,000 km) at a cost of US \$0.75 – 2.60/kg. Small-scale distribution pipelines (10 – 100 tpd) for up to 500 km are likely to cost between US \$0.05 – 2/kg. In contrast, transmission pipelines are likely for scales of 100 – 1,000 for 10 – 10,000 km at a cost of US \$0.05 – 2/kg. Shipping is likely to be considered for 5,000 km or larger ranges or 10 – 1,000 tpd with a cost over US \$2/kg.⁶⁶



Notes: A typical pressure for compressed hydrogen trucks is 500 bar for a 1.1 t capacity (Wulf et al., 2018).
Source: (Energy Transition Commission, 2021a; Li et al., 2020).

FIGURE 10. ESTIMATED COST OF HYDROGEN TRANSPORT TECHNOLOGY PATHWAYS. IMAGE REPRODUCED WITH PERMISSION OF IRENA FROM THE TECHNOLOGY REVIEW OF HYDROGEN CARRIERS REPORT 2022.⁶⁶

H₂ Storage and Distribution in the PICTs – Opportunities and Challenges

Development of a gaseous H₂ storage and distribution network in the PICTs may be a challenge due to the lack of existing infrastructure and a trained workforce. At present, only PNG has significant gas infrastructure, focused on LNG exports. Therefore, implementing an H₂ distribution network would require considerable capital investment in compression, storage facilities, in-country distribution networks, and end-use equipment retrofitting to make them H₂-ready. Development costs would also be impacted by the remoteness of the PICTs and the lack of local support and operational workforce. However, the development of hydrogen pipelines and transport networks between specialised H₂ production sites and industrial hubs could be mutually beneficial, for example, targeted distribution networks in New Caledonia to support the mining industry, distribution of goods to port sites, and use in shipping.

The deployment of pipelines or tube trailers could be a means for energy distribution to remote regions (that are not currently connected to the grid); bulk amounts of hydrogen can then be transported at these locations for on-demand energy generation.

Given the reliance of the region on liquid fossil fuels, the development of a liquid H₂ network may be feasible due to regional experience and infrastructure. However, the transition to liquid hydrogen would entail retrofitting, given the cryogenic need for keeping the hydrogen liquified.

Note: Report C will conduct an in-depth analysis of existing infrastructure in the PICTs that can be leveraged for H₂ storage and distribution, as well as additional infrastructure that would have to be developed. A further concern is policy and safety regulations; the International Standard Organisation (ISO) has established standards for H₂ technology including production, storage, distribution, and end use that are globally applicable.⁶⁷ Regionally, Standards Australia is also working on the development of standards for the H₂ industry that can be translated into the PICTs.⁶⁸

3.2. Hydrogen Utilisation Technology

Industrial use of H₂ until recently has been mostly focused on use in oil refining, and manufacturing of ammonia fertilisers, methanol, and plastics, accounting for 95 Mtpa of H₂. In an emerging H₂ economy, there is likely to be an increase in demand for ammonia and methanol as energy carriers of the future (*discussed below* for ammonia (**Section 4**) and methanol (**Section 5**)). There are also opportunities to scale biomass-based H₂ to generate synthetic fuels such as renewable diesel and SAF, that can be used as drop-in replacements for their fossil fuel-based alternatives, these opportunities are elaborated *below* (**Section 6**).

H₂ on its own is expected to be a renewable energy carrier to complement renewable energy and deliver it to hard-to-abate sectors. This opportunity is driven by the ability to generate hydrogen from renewable energy (via electrolysis), further complemented by the inherent ability of hydrogen to be stored and distributed in bulk amounts with minimal losses for reconversion to energy on demand, as well as without any harmful emissions. As such, with the development of fuel cells and hydrogen turbines, there are opportunities for H₂ to generate on-demand power that can be supplied to the grid or as an isolated

microgrid and used for mobility applications in fuel cell electric vehicles. These opportunities are elaborated *below*.^{viii}

3.3. Status of H₂-based Energy Storage and Production Technology

Hydrogen Fuel Cells

Fundamentally, hydrogen fuel cells work in the reverse of electrolyzers, where oxygen and H₂ are fed in as fuels, with electric power (and heat) and water generated as the products. Fuel cells are being actively developed as power generation facilities, such as the one shown in **Figure 11**. H₂ can be transported to these facilities or renewables can be deployed with electrolyzers to generate H₂ onsite. Such multi-generation power solutions could be important for PICTs to create self-contained power solutions for remote, off-grid, or islanded communities.



FIGURE 11. STATIONARY FUEL CELL SOLUTIONS FOR POWER GENERATION. IMAGE COURTESY OF PLUG POWER.

The outlook of fuel cell technology for power generation is provided below:

Status of Technology

Globally, 400 – 500 MW of fuel cell systems have been deployed.² Several types of fuel cell systems have been developed, including (i) Polymer Membrane Fuel Cells (PEMFCs), (ii) Alkaline Fuel Cells (AFCs), (iii) Phosphoric Acid Fuel Cells (PAFCs), (iv) Solid Oxide Fuel Cells (SOFCs) and (v) Molten Carbonate Fuel Cells (MCFCs). These can operate on a range of fuels including H₂, ammonia, methanol, and other hydrocarbons. These types are all still ongoing in different stages of their R&D, with PEMFC, MCFCs, PAFCs and SOFC reaching both high technical and commercial maturity for use in power generation. Several companies (**Figure 12**) including Ballard, Plug Power, and Nuvera are retailing PEMFCs, whilst Bloom Energy, Siemens and Sunfire are retailing SOFCs, Doosan Fuel Cells are developing PAFCs, and FuelCell Energy are developing MCFCs.

^{viii} **Note:** It is important to acknowledge that H₂ faces competition from direct electrification and battery technology. Therefore, wherever applicable in the sections *below*, a comparative assessment of H₂ solutions against these technologies is provided to highlight hydrogen's competitive advantages and limitations.

PEMFCs	PAFCs	SOFCs	MCFCs
 		  	

FIGURE 12. LIST OF LEADING GLOBAL FUEL CELL MANUFACTURERS.

Technical and Economic Outlook

The present targets for fuel cell technology systems include energy efficiency of >45% (with combined power and heat of 90%), dynamic loading of 1.5%/sec (10% to 90% load ramping in 2 mins), startup time of 20 mins, cost of US \$1,500/kW, and durability of 60,000 hrs.⁶⁹ **Table 11** provides a comparative summary of the fuel cells for power generation applications. Of all the available classes, PEMFCs are the most likely option for the PICTs, due to their scalability, moderate operating conditions, high efficiency, and power/energy densities. However, it is important to note that the costs of PEMFCs are sensitive to scale, the costs at small scale (<100 kW applications) can be up to 5 times higher than at higher capacities (>500 kW). However, 100 kW – 1 MW power capacities are likely for isolated communities.

TABLE 11. TECHNO-ECONOMIC OUTLOOK OF FUEL CELLS FOR POWER GENERATION APPLICATIONS.^{69–72}

Parameter	PEMFCs	PAFCs	MCFCs	SOFCs
Technical Parameters				
Fuel	H ₂ /Methanol (CH ₃ OH)		H ₂ /Methane (CH ₄)/Carbon Monoxide (CO)	
Op. Temp (°C)	-40 to 90	150 to 200	650 to 700	600 to 1000
Elec. Eff. (%)	35% – 50%	~40%	~50%	35% – 60%
CHP Eff. (%)	85% – 95%	Up to 90%	85% – 95%	75% – 95%
Durability (hrs)	Moderate to High (60,000 – 80,000)	Low to High (30,000 – 130,000)	Low to Moderate (20,000 – 30,000)	Low to High (40,000 – 90,000)
Power Density (kWh/m ³)	110 – 770	NA	25 – 40	170 – 460
Specific Energy (Wh/kg)	100 – 450	NA	370 – 600	400 – 1,500
Scale	Few W to MW	100 kW to 10 MW	500 kW to 100 MW	1 kW to 100 MW
Economic Parameters				
System Costs (US \$/kW)	US \$3,000/kW to US \$4,000/kW at >500 kW scale >US \$20,000/kW at <100 kW scale	US \$4,000/kW to US \$5,000/kW at scale of 10 MW or higher	US \$4,000/kW to US \$6,000/kW at MW scale	US \$3,000/kW to US \$4,000/kW at >200 kW scale
Energy Costs (US \$/kWh)	70 – 13,000	NA	146 – 175	180 – 333

Operating Costs
(excluding the cost of
H₂ fuel but including
stack replacement)

Scale Dependent:

- For 0.3 – 5 kW systems: US \$5 – 20/MWh (Avg: US \$12/MWh)
- For 5 – 400 kW systems: US \$3 – 7/MWh (Avg: US \$5/MWh)
- For >500 kW systems: US \$3 – 5/MWh (Avg: US \$4/MWh)

Fuel Cell Power Opportunities in the PICTs

In the PICTs, fuel cells have the potential to be deployed as multi-generation power systems as a replacement for diesel generators, especially in remote/off-grid communities. The development of such projects is already underway in the PICTs; as highlighted in **Report A**, HDF Energy is developing a fuel cell based multi power generation facility in Fiji and the Pacific Green Hydrogen Project is exploring similar opportunities for Cook Island, Fiji, Tonga, and Samoa.^{73–75} H₂ can also be used to provide heating, for example, excess heat is generated while operating fuel cells that can be recovered to create a combined heat and power system (CHP).^{76,77} Such CHP systems can be used for domestic and commercial heating, e.g., in the context of the PICTs, an H₂-based CHP system can be used to power to tourist resorts and industry. They can also be used for industrial applications like to support energy use of desalination plants that can serve both H₂ generation and local water supply. In addition, fuel cell systems are being increasingly deployed for backup power for critical infrastructure, such as data centres and telecom towers that require reliable power in case of primary energy supply failure. In the PICTs, such systems can be deployed for critical infrastructure including telecom towers, water utilities, and hospitals.



FIGURE 13. EXAMPLES OF HYDROGEN FUEL CELL APPLICATIONS AS A BACK-UP POWER SOURCE FOR CRITICAL INFRASTRUCTURE. FUEL CELLS ARE BEING INCREASINGLY USED FOR THEIR RELIABILITY WHICH IS IMPORTANT FOR APPLICATIONS LIKE DATA CENTRES (FUEL CELL INSTALLED AT A MICROSOFT DATA CENTRE IS SHOWN ON THE IMAGE ON THE LEFT) AND FOR TELECOMMUNICATION TOWERS (AS SHOWN ON THE IMAGE ON THE RIGHT).

Hydrogen Turbines

Hydrogen fuel-ready gas turbines are also emerging as an option for large-scale power generation due to their compact size, flexibility, and dynamic operability. Presently, these turbines are being developed with the ability to accept dual fuels (natural gas and hydrogen blends) and as a 100% H₂ fuel-ready turbine. Companies including General Electric, Mitsubishi Power, Siemens, and MAN Energy have developed and commercialised H₂ turbines albeit these don't currently run on 100% H₂ blends (**Figure 14**).








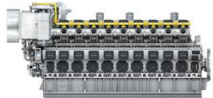
 GE Power			
General Electric	Siemens	Mitsubishi	MAN Energy
 <p>GE has various models of H₂ fuel ready gas turbines. These include the Aeroderivative, B/E Class and F-Class turbines that can operate at 100% H₂ fuels. Their most efficient and modern gas turbines is the H Class turbines that can operate at 50% H₂ blends with energy efficiency of 60% higher.</p>	 <p>Siemens also offers various models of H₂ ready gas turbines. These include the SGT5-6 Series, SGT400 – 800 series and SGT-AO5. These turbines have been installed and operated at upto 600 MW scale power outputs with upto 75% blends of H₂. The company is developing solutions to scale these to 100% gas ready systems by 2030.</p>	 <p>Mitsubishi also has ambitions for developing 100% H₂ ready gas turbines. These include their H-25/100 series, M501 and M701 series turbines that can operate at 30 to 100% H₂ fuel blends.</p>	 <p>MAN Energy are developing H₂ powered engines that can be used for power generation. These include their M35 series and M51 that can operate at 25% H₂ fuel blends. The company is also presently developing 100 H₂ fuel turbines.</p>

FIGURE 14. EXAMPLES OF COMMERCIAL HYDROGEN FUEL READY GAS TURBINES.

A key market for the development of these turbines is to enhance the use of the natural gas-based power network, with natural gas systems being preferred to coal and diesel generators for grid operations due to their lower environmental footprint and greater flexibility.⁷⁸

Hydrogen Turbine Power Opportunities in the PICTs

At present, there is no gas power infrastructure in the PICTs (except for a few biogas-based power projects). However, replacement of diesel generators with a gas turbine would technically be more straightforward than replacing with solar and wind generators; especially given the intermittency of these resources, H₂ turbines could be used to dynamically respond and provide power during high demand (and renewable generation shortfalls). Hydrogen-diesel engines could also potentially replace diesel internal combustion engines. Nevertheless, the cost of H₂ fuel and the additional limit of operating these peaking powerplants (intermittent operation) need to be considered which would increase the electricity costs. Estimates show that the electricity generation cost of H₂ peaking plants would be US \$150 – 300/MWh (for a cost of H₂ of US \$3/kg).⁷⁹ In comparison, based on current natural gas fuel costs, the electricity costs would be US\$100 – 200/MWh. Therefore, a green premium, subsidy, or carbon tax would likely have to be applied to make this a competent application.⁸⁰ This is of course a best-case economic comparison for the region given that H₂ production costs will be higher than in regions able to support very large-scale projects, and even if imported from such regions, will incur shipping and other costs. Fuel costs alone with diesel gensets in the Pacific can be over US \$200/MWh.



FIGURE 15. H₂ GAS BASED POWERPLANTS. H₂ FUEL-READY GAS TURBINES ARE BEING INSTALLED IN RETROFITTED OR NEWLY BUILT NATUREL GAS-BASED POWERPLANTS. FOR EXAMPLE, THE ABOVE FIGURE SHOWS THE TALLAWARRA NATURAL GAS POWERPLANT IN AUSTRALIA, WHERE A HYDROGEN-READY TURBINE HAS BEEN INSTALLED THAT WILL OPERATE WITH A 5% H₂ FUEL BLEND BY 2025 AS A DEMONSTRATION PILOT PROJECT.

Fuel Cells vs. Diesel and Electrification for Power Generation in the PICTs – Opportunities and Challenges

In the PICTs, fuel cells have an opportunity to replace diesel generators, especially in remote off-grid locations. Fossil fuel use for electricity has a significant emission and economic footprint in the PICTs; 2.7% of regional GDP and 6 MTPA of CO₂ emissions (see **Report A**).

Fuel cells can directly displace this fossil fuel use and associated emissions, as a standard diesel generator requires ~0.3 L/kWh of diesel⁸¹ and would generate ~7 kgCO₂/kWh (given a diesel emission factor of 2.7 kg CO₂/litre of diesel).⁸²

However, a significant challenge is the cost of fuel cells; on a kW basis, a diesel fuel generator is roughly 20 times cheaper than an equivalent fuel cell. Our preliminary analysis indicates that the cost of a 100-kW diesel generator would be ~US \$200 per kW, compared to a fuel cell cost of US \$4,000 per kW. This would yield an electricity cost of US \$0.40 per kWh (under current diesel costs of US \$1.5/litre^{ix}) against a US\$ 0.60 per kWh from the fuel cell system (assuming a H₂ fuel cost of US \$6 per kg^x); a cost difference of about 1.5 times.

^{ix} The energy cost of the diesel generator was estimated based on a 100 kW genset (operated at a 80% power factor) with a capital cost of generator of US\$200/kW, operating for 8 hrs a day/365 days a year at a fuel cost of US\$ 1.5/litre (with a peak fuel demand of 24 litre/hour) and an additional O&M cost of US\$0.01/kWh. The cost of energy was then established by the standard levelised cost of energy assessment assuming a WACC of 7% across a 20-year lifetime.

^x Similarly, the cost of fuel cell assumed a 100-kW fuel cell (with a 80% power factor), operating at 50% efficiency on LHV basis, with a capital cost of fuel cell of US\$4,000/kW, operating for 8 hrs a day/365 days a year at a H₂ fuel cost of US\$6/kg, H₂ storage cost of US\$300/kg and an additional O&M cost of 5% of Capex. The cost of energy was then established by the standard levelised cost of energy assessment assuming a WACC of 7% across a 20-year lifetime.

However, given the sensitivity to diesel price (the overall cost is driven by fuel prices); a fuel cost increase to US\$2 per litre might achieve parity with fuel cells. This is likely, given that fuel prices are increasing globally year on year and the cost of fuel delivery to remote regions is often significantly higher compared to urban centres. In comparison, the cost of hydrogen generation is likely to go down with economies of scale and ongoing R&D.

Compared to direct electrification with solar or wind energy, a fuel cell system would have a significant disadvantage due to the roundtrip energy efficiency of electricity conversion to hydrogen via electrolysis, and subsequent conversion of hydrogen to power using a fuel cell. Considering that 1 kg of hydrogen requires ~50 kWh of energy (**Table 6**) and a fuel cell generates 15 kWh/kg of H₂ (assuming a 50% fuel cell efficiency – **Table 8**); a fuel cell would yield a round trip efficiency of 30%. Resulting in 0.3 MWh of electricity produced by a fuel cell; for every 1 MWh of energy converted to H₂ fuel for the fuel cell via the electrolyser (assuming negligible H₂ losses between the electrolyser and fuel cell). Therefore, significantly larger amounts of renewable energy would be needed to deliver power from fuel cells. However, the key advantage is that a fuel cell provides a stable and reliable power (provided there is H₂ fuel availability) compared to solar and wind energy, that are intermittent and variable.

Firming of renewables can also be achieved with battery systems, which have a higher round trip efficiency of over 90% and lowering costs. Yet, discussion with stakeholders that are developing battery systems in the PICTs have revealed that battery systems exhibit energy losses and integrity issues due to the harsh temperature and humidity conditions in the region. This could be a critical shortcoming for long duration storage and for critical applications where reliability is important. As such, long term energy storage in form of hydrogen and derivatives for reconversion to electricity through fuel cells could be more viable, as though fuel cell performance is also impacted by ambient conditions (high temperature and quality of fuel) and H₂ fuel pressure; they tend to be more reliable in terms of performance. Yet, the cost of fuel cells and integration with large capacity hydrogen storage is risky and costly, these trade-offs will be explored in greater detail in **Report C**.

3.4. Status of H₂-Based Mobility Applications

The development of fuel cells and electric-powered vehicles is creating opportunities for H₂-based mobility. These fuel cell electric vehicles (FCEVs) rely on a hydrogen fuel cell for electric power that drives the electric motor. H₂ fuel cell drive train options have been developed for a wide range of vehicles including forklifts, small light-duty vehicles, buses, and trucks.

Toyota, KIA, and Hyundai are pushing the development of small-scale passenger vehicles, whilst Van Hool and Mercedes are developing fuel-cell buses, and Hyundai, Scania and Hyzon are developing fuel-cell trucks (**Figure 16**).



FIGURE 16. SOME COMMERCIAL FUEL CELL VEHICLE DEVELOPERS.

FCEVs are gaining traction due to competitive performance (load-bearing capacities and ranges compared to BEVs and internal combustion engine vehicles), with the additional advantage of quicker refuelling (compared to BEVs). The limitations, however, are higher upfront costs and infrastructural needs. FCEVs in general cost 1 – 3 times more than their diesel counterparts, the cost of H₂ fuel per km is 1.2 times higher compared to diesel, and the cost of H₂ refuelling stations is 5 – 10 times higher than diesel fuel stations. They are also competing against the rapid progress currently being seen with battery EVs. Therefore, there is an expectation that FCEVs might only be competitive in the long run as the cost of vehicles, fuel, and infrastructure reduces considerably (most likely post-2040) and mostly likely in specific sectors such as heavy-duty long-haul transport.^{79,83,84}

TABLE 12. TECHNO-ECONOMIC COMPARISON OF FCEVs AGAINST DIESEL AND BATTERY ELECTRIC COUNTERPARTS.^{79,83–87}

Parameters	Diesel Vehicles	BEVs	FCEVs
Technical Parameters			
Emissions (kgCO ₂ /km)	0.1 kgCO ₂ /km	Zero assuming electricity and supply of H ₂ fuel are green	
Well to Tank Efficiency	~86%	~55%	~23%
Tank-to-Wheel Efficiency	~23%	~68%	45 – 50%
Fuel Con. (km/unit)	~2.8 km/litre	~0.8 km/kWh	~9 – 15 km/kg
Range (km)	1,500 – 3,000 km	100 – 800 km	1,100 – 1,800 km
Economic Parameters			
Cost of Vehicles (relative to diesel vehicles)	1	1 – 5 times higher than diesel	1 – 3 times higher than diesel
Cost of Fuel (\$/unit)	US \$1.3/litre	US \$0.3 – 0.6/kWh	US \$3 – 6/kg
Cost of Refuelling Station (relative to diesel)	1	2 – 5	5 – 10

Fuel Cells vs Diesel and Electrification for Mobility in the PICTs – Opportunities and Challenges

Fuel cell-based mobility is an additional opportunity for renewable electrolysis use. The advantages FCEVs have over conventional fossil fuel internal combustion engines (ICE) and BEVs are the competitive range, no emissions, and a small footprint/weight of drive train and fuel tank (H₂ has a significantly higher energy density, especially at pressure, that allows larger amounts of energy to be stored for a given volume of storage). Nevertheless, FCEVs are limited by their higher upfront cost of vehicle, infrastructure, and fuel, as highlighted *above*. In addition, FCEVs have a lower energy efficiency on both well-to-tank and well-to-wheel basis than BEVs, which means much more energy from renewable resources would be needed to power an FCEV fleet compared to BEVs. A further consideration for the PICTs is the quality of infrastructure, such as the roads used for transportation – it is likely that trials and demonstrations would need to be carried out to determine if FCEVs are compatible with existing PICTs infrastructure.

Despite these challenges, hydrogen is emerging as a key option for operations requiring faster turn around and heavy haul/duty operations.⁷⁹ Therefore, in the PICTs, FCEVs can gain a share of niche markets including forklifts, specialised applications such as mining trucks, garbage collection, delivery trucks, construction equipment, and heavy-duty/long haul applications.

Note: FCEVs also face competition from other renewable synthetic fuels such as methanol and renewable diesel (discussed *below*). These fuels can be deployed as a drop-in replacement for diesel without the need for drastic changes to the refuelling network and vehicles.

3.5. Summary of Hydrogen Technology in the PICTs

This section focuses on the state of play of hydrogen technology and highlights the growing potential in the global race to decarbonisation. The key advantage that hydrogen provides is its ability to be generated from renewable electrification, and act as a carrier to spread this renewable energy across the wide spectrum of end uses. For the PICTs, these opportunities include power and mobility applications as summarised in **Table 13**, as well as the opportunities to generate hydrogen derivatives, elaborated *below*. H₂ can enable a self-sufficient energy supply in the PICTs, however, several challenges would have to be overcome, including the significant scale of infrastructure development required to adopt a hydrogen energy system. This will be further impacted by the present lack of local workforce and local expertise and the remoteness of the region. These challenges can be addressed through strategic investment, collaboration, and compliance with global stakeholders.

Additionally, it is important to acknowledge the intrinsic limitations of hydrogen technology, particularly its round-trip efficiency, which leads to the requirement for significantly higher amounts of renewable energy compared to electrification with the support of battery systems. However, competing opportunities for H₂ can still be realised given the higher energy density of H₂ and the potential higher reliability compared to battery systems (however this is not determined yet) and H₂ technology being more versatile in its end uses. Altogether, the Pacific region is an emerging market, with an urgent need and desire to decarbonise, therefore opportunities and room for both electrification and hydrogen offtake remain; both solutions can work in tandem to deliver a decarbonised future.

TABLE 13. IDENTIFIED OPPORTUNITIES FOR H₂ TECHNOLOGY IN THE PICTs.

Power Applications	Description	Development required	Benefits
Microgrid applications	Solar PV and wind turbine-assisted electrolysis/fuel cell systems can be developed to provide reliable standalone power systems.	Diesel generators would become redundant and need to be replaced with costly fuel cell backup power systems. High investment costs	The transport sector in the PICTs consumes ~14 million barrels of diesel equivalent (Report A). Displacing 1% of this demand will yield in saving of US \$13 million in fuel import savings and 60 ktpa of emission saving. Moreover, given the hydrogen generation and use systems are CAPEX driven, and the major variable cost is hydrogen fuel which can be secured with fixed energy pricing, the electricity generation costs from fuel cells/turbines can effectively be hedged at a stable level compared to diesel price that will fluctuate based on international market dynamics.
Grid backup	Hydrogen peaking plants can be developed through H ₂ -ready gas turbines.	New infrastructure and equipment are required, which would be further impacted by the lack of existing gas networks and experience in the region.	
Mobility Applications	Description	Development required	Benefits
Heavy-duty and specialised vehicles	H ₂ fuel cell vehicles can be deployed for heavy-duty and haul applications such as freight or mining trucks.	H ₂ refuelling and distribution network would have to be developed.	The transport sector in the PICTs consumes ~7 million bbl diesel equivalent (Report A). Displacing 1% of this demand will yield US \$7 million in fuel import savings and 30 ktpa of emission reductions.

Water Availability for a H₂ Economy in the PICTs – Opportunities and Challenges

Water is a critical requirement for electrolysis, with 9 kg of H₂O required stoichiometrically per kg H₂ produced. However, commercial electrolyzers require deionised water with low conductivity (< 1 µS/cm) and low total organic carbon (TOC), and purification of available water sources (such as seawater) can more than double the water requirement before factors such as cooling are considered, as reverse osmosis (RO) might recover only 40-50% of water as the permeate.⁸⁸

Water is of course a key resource across most of the Pacific. The region does have some experience with RO plant operation. The cost of seawater desalination typically ranges from US \$0.70 – 2.50 per m³ of treated water, depending on the system scale and feed water quality, however, this cost can increase to above US \$3.00 per m³ for smaller and decentralised systems.^{89,90} Energy requirements for seawater desalination can range from 3 – 6 kWh per m³ of treated water.^{29,91} In general, the energy and cost requirements for water desalination and purification are significantly lower than the energy and cost of hydrogen generation via electrolysis. The cost of water deionisation is estimated at around 20% of a PEM plant cost, whilst the energy required for deionisation represents less than 1% of the energy stored in the produced hydrogen.^{29,92}

Suppliers of decentralised RO systems for water treatment include Veolia, Aquastill, Fluence, Mork Water, and Puretech.^{93–97} These systems can produce around 100 – 1500 m³ per day of treated water, equivalent to ~1.8 – 27 ktpa of H₂, matching the preliminary estimates of the H₂ demand for several PICTs (**Table 2**) (assuming 20 kg of H₂O per kg H₂). Some systems are RO processes only, whilst others include the electrodeionisation or ion exchange processes required to produce the water quality needed for PEM electrolysis.



FIGURE 17. VEOLIA'S TRITON PLUG & PLAY RO-CEDI SOLUTION.

Seawater is not the only potential source of water for hydrogen production in the PICTs – the costs of water purification are similar for wastewater from sources including municipal, industrial, and resource extraction (wastewater from natural gas/oil and mining), as well as brackish groundwater.⁹²

Wastewater or rainwater reclamation systems may be preferred to seawater desalination, as they would require less processing to deionise the water. PICTs such as Fiji, New Caledonia, and PNG could potentially employ industrial or resource extraction wastewater as the feed to an RO system.

A key consideration in the PICTs is the disposal of the reject brine from RO processes, which contains a salt load approximately twice that of seawater, potentially causing adverse effects to coastal waters and aquatic life upon discharge. There are several technology providers that offer zero liquid discharge (ZLD) solutions, converting reject brine into fresh water and potentially valuable mineral by-products, such as Mg and K based fertilisers.⁹⁸⁻¹⁰¹ This may be a potential pathway to improving local crop yields without relying on imported fertilisers or the domestic production of ammonia. Moreover, the development of desalination plants for the hydrogen economy in the PICTs can also benefit and boost the local clean water supply for domestic use.

4. Renewable Ammonia

Ammonia (NH_3) is an industrially important chemical, conventionally employed as a precursor to products such as fertilisers and solvents. The wide-spread use of ammonia is attributable to the development of the Haber-Bosch process in the late 19th century, aiding in the production of synthetic nitrogen-based fertilisers, and contributing to a buildup of reactive nitrogen in the biosphere, causing an anthropogenic disruption to the nitrogen cycle. As of 2022, 150 Mtpa of ammonia is produced globally, the majority of which is used as a chemical precursor.¹⁰²

As a hydrogen derivative and considering its ability to be produced and used with zero carbon emissions, green (or renewable) ammonia has been identified as a promising Power to X fuel, with application to various end-use sectors (**Figure 18**). Green ammonia demonstrates the potential to be integrated into the Pacific region, assisting in driving decarbonisation in hard-to-abate sectors. Ammonia can be produced with zero CO_2 emissions, by using renewable energy to produce hydrogen and separate nitrogen from air. Despite this production pathway contributing <1% of the current global ammonia supply, the influx of hydrogen roadmaps, policies, and incentives has also led to significant investment into green NH_3 projects.¹⁰³ It is therefore projected (in a Net Zero Emission by 2050 scenario) that ammonia produced through electrolysis could eventually contribute to 40% of the global supply.¹⁰³

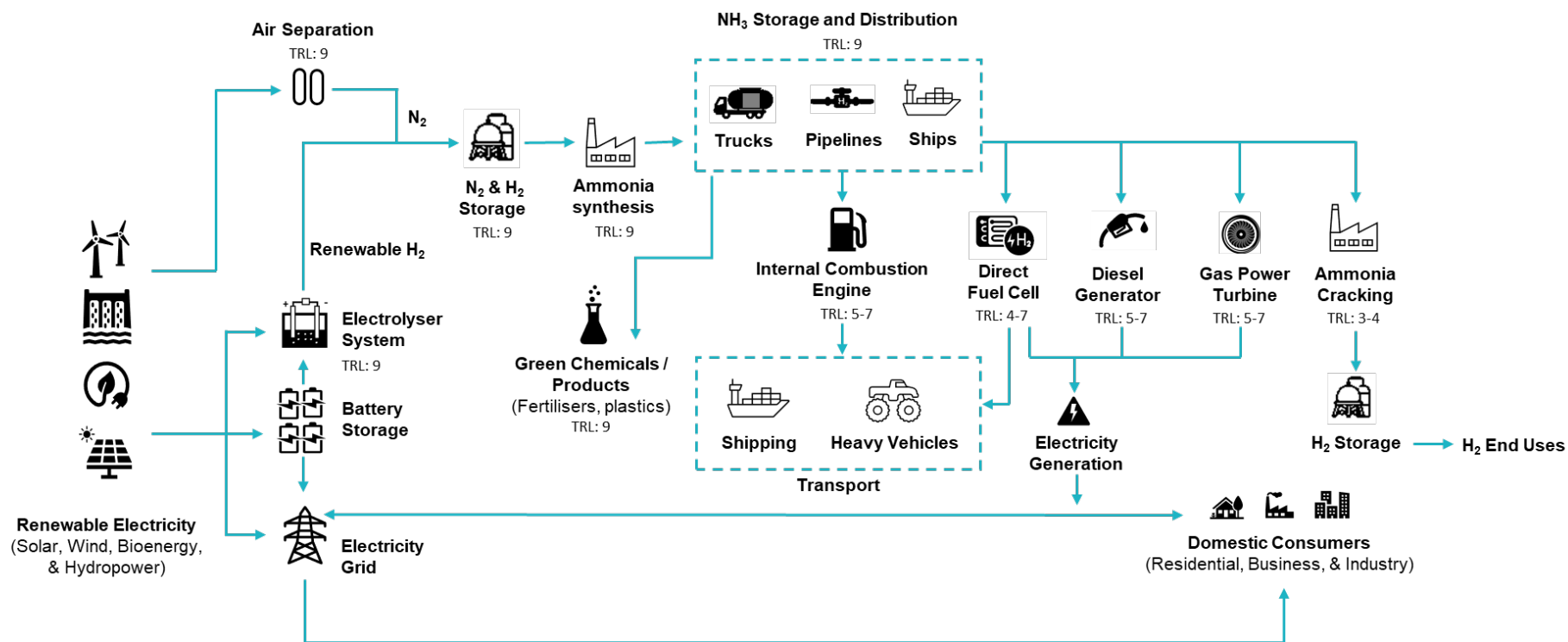


FIGURE 18. THE RENEWABLE AMMONIA VALUE CHAIN. THE VALUE CHAIN COVERS PRODUCTION, STORAGE, DISTRIBUTION, AND APPLICATIONS. THESE ARE DISCUSSED IN THE FOLLOWING SECTIONS. THE TECHNICAL MATURITY OF THE TECHNOLOGY EMPLOYS THE CONVENTIONALLY USED TECHNOLOGY READINESS LEVEL INDEX.

4.1. Renewable Ammonia Production

Ammonia is colourless gas at standard temperature and pressure. It is traditionally produced through the Haber-Bosch process. The catalytically moderated conversion of hydrogen and nitrogen feedstocks is optimised by high pressures (150 – 200 bar) and moderate temperatures (400 – 500°C).¹⁰⁴ The production of these feedstocks (hydrogen and nitrogen) is conventionally integrated into the process, rather than outsourced. Hydrogen feedstock is conventionally produced by fossil fuel feedstocks, relying on steam methane reforming (SMR) (72%) or coal gasification (26%), whilst nitrogen is separated from air.¹⁰⁵

This integration has allowed improved heat integration and scale-up opportunities, furthermore, optimising of process efficiency over time. Today, ammonia facilities are generally large in scale, on average producing around 500 ktpa of ammonia,¹⁰⁶ with the industry contributing to 1.2% of the global CO₂ emissions.¹⁰⁵ As such, efforts to decarbonise ammonia's production are increasing, with green ammonia expected to contribute to up to 40% of global ammonia production by 2050.¹⁰⁷

Renewable Energy Integration

Ammonia production can be decarbonised through integrating renewable energy throughout the process. Ammonia synthesis through the Haber-Bosch process functions independently of the source of hydrogen, meaning that renewable electrolysis (the separation of water by electricity, [Section 3](#)) can be easily employed to produce hydrogen feedstock rather than SMR or gasification. Electrolysis accounts for around 95% of the required electricity for electrolytic ammonia production.¹⁰⁷

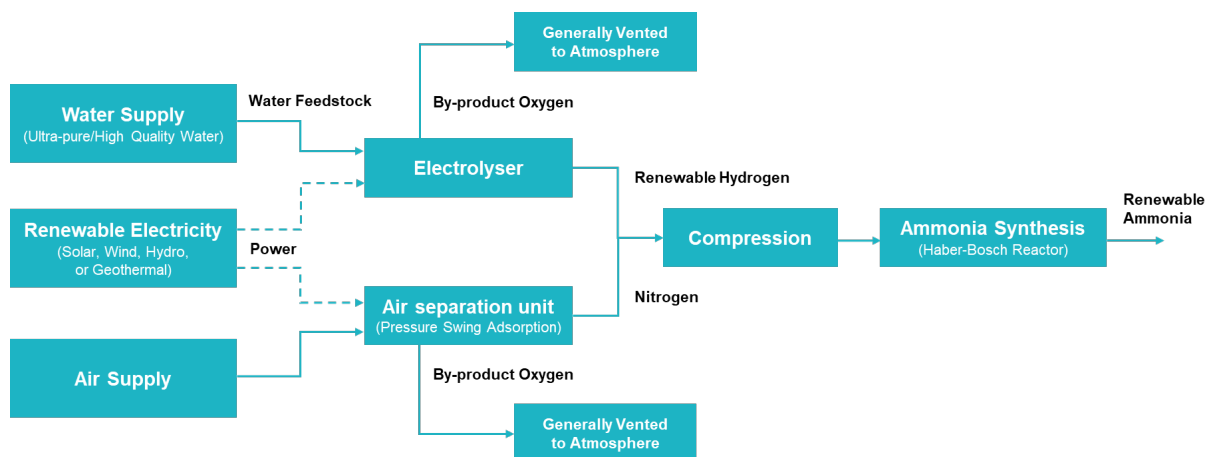


FIGURE 19. THE RENEWABLE AMMONIA PRODUCTION PATHWAY. HYDROGEN (PRODUCED VIA WATER ELECTROLYSIS) AND NITROGEN (SEPARATED FROM AIR) ARE CATALYTICALLY REACTED TO SYNTHESISE AMMONIA.

The air separation technology used for the nitrogen feedstock is required to be standalone and can incorporate renewable energy with ease.¹⁰⁸ [Table 14](#) details the feedstock requirements to produce renewable ammonia.

TABLE 14. FEEDSTOCK REQUIREMENTS FOR ONE KILOGRAM OF AMMONIA.^{109,110}

Feedstock Requirement (per kg of NH ₃)	
Energy consumption (including electrolysis, N ₂ separation, NH ₃ synthesis, and storage)	▪ 13.9 kWh
Hydrogen required	▪ 0.177 kg
Nitrogen required	▪ 0.823 kg
Water required (for hydrogen production)	▪ 9 L (stoichiometrically)

Technology Maturity of Renewable Ammonia Production Technologies

The production of renewable ammonia via the electrolysis of water and the Haber Bosch process is technically and commercially mature, with all processes involved exhibiting a TRL of 9. However, there are several primary production challenges facing this pathway, including:

- **Efficiency.** Due to the maturity of conventional ammonia production, the efficiency of the process has been optimised through the incorporation of heat integration and minimisation of pressure and temperature. With the use of electrolysis in green ammonia production, further optimisation of the system is required.
- **Intermittency of renewable energy.** Fluctuations in energy availability must be considered to achieve continuous operation, with balancing technologies required to supply a consistent hydrogen supply.
- **High cost.** Significant capital expense and operating costs are associated with renewable energy generation and the electrolyser operation (*see below*).

Other renewable pathways are in the early stages of development. For example, there are several alternative approaches to generating low or zero-carbon hydrogen (as detailed in [Section 3](#)), such as methane pyrolysis (a process that uses heat to split methane into hydrogen and solid carbon), biological hydrogen production (a process that uses microorganisms and sunlight to turn water, and sometimes organic matter, into hydrogen), or from biomass.^{111,112} These can then be partnered with the Haber Bosch process for ammonia synthesis.

Electrochemical methods for renewable ammonia generation are also in development, which involve the use of either hydrogen and nitrogen, waste NO_x gases, or waste aqueous nitrates, as feedstock to produce ammonia in an electrochemical cell via the application of an external bias.¹¹¹ Plasma can also be employed to generate NO_x from air and water, which can then be electrochemically converted to ammonia.¹¹³ These processes are renewable if powered by renewable electricity.

However, the low TRL for these pathways likely hinders their application to the PICTs within the short to medium term.

Costs

Capital and operating costs are one of the biggest implementation barriers for green ammonia projects and therefore must be considered when assessing the technology. At present, the cost of green ammonia is estimated in the range of US\$720 – 1400 per tonne. Green ammonia produced in decentralised facilities (that do not exhibit economies of scale) has been estimated at around US\$900 per tonne.^{114,115} Driven by increased availability and lower cost of renewable electricity, and the reduction in electrolyser costs, green ammonia costs could reach the range of US\$310 – 610 per tonne by 2050.¹¹⁶

There is a clear price disparity when comparing green ammonia with ammonia produced with fossil fuels, with the cost per unit of fossil fuel-based ammonia ranging from US\$110 – 340 per tonne NH₃.^{114,115} However, carbon capture and sequestration would add around US\$100 – 150 per tonne, increasing the cost to US\$210 – 490 per tonne. This price disparity between fossil-based and renewable ammonia is primarily attributable to the cost of green hydrogen production, including electricity price, electrolyser costs, and water processing. Detailed discussion on these factors can be found in [Section 3](#).

Commercial Players

Various key players have commercialised decentralised green ammonia production facilities using conventional reaction processes ([Table 15](#)). For example, Thyssenkrupp has commercialised green ammonia technology with a capacity of 50 – 300 tpd. Within this capacity range, a similar capital and operating expenditure to conventional small-scale ammonia production is achievable.¹¹⁷ Proton Ventures similarly delivers decentralised and modular power-to-ammonia systems of around 2 tpd of ammonia.¹¹⁸ The facility is fully automated and skid-based, highlighting its application to remote locations.¹¹⁹ FuelPositive has also recently commercialised a small-scale green ammonia system with the ability to produce 0.3 tpd.¹²⁰ The system is containerised and able to operate within three standard 20 ft containers, and could therefore also be easily installed in remote and isolated regions.

TABLE 15. COMMERCIALISED GREEN AMMONIA TECHNOLOGY VENDORS AND CAPACITIES.^{117,119–122}

Company	Technology Name	Scale	Capacity (tpd)
KBR	K-GreeN	Large	>1000
Linde	LAC	Large	230 – 1350
Topsoe	SynCOR Ammonia	Large	~6000
Thyssenkrupp	-	Medium	50 – 300
Proton Ventures	NFuel	Small-Medium	2 – 300
FuelPositive	-	Small	0.3

4.2. Ammonia Storage and Distribution

Storage Technology

Ammonia is most commonly stored as a liquid, which can be achieved either cryogenically ($\sim -33^{\circ}\text{C}$) or under pressure ($\sim 1.7\text{ MPa}$). Storage tanks are constructed with non-corrosive metals, such as carbon steel or stainless steel. Furthermore, storage tanks and facilities must be equipped with specialised safety features, such as pressure relief valves and ventilation, to mitigate the risk of ammonia toxicity.^{123,124}

As ammonia is a widely used and distributed chemical, purpose-built storage tanks are commercialised and mature in their use and are readily available on the market. Horizontal cylindrical tanks that are pressurised or semi-refrigerated are the most applicable for small-scale ammonia storage and could be considered in decentralised ammonia facilities.¹²³

Distribution Technology

Large-scale distribution of ammonia can be carried out by pipelines, ship, rail, or truck transport. Transport via pipelines is feasible for the distribution of large volumes of ammonia to fixed locations, with extensive planning and infrastructure development needed to implement effective pipeline networks. In the context of the PICTs, ammonia distribution through pipelines is a land-based system, making distribution within the region (across the land or sea either domestically or internationally) difficult, and requiring significant capital investment.

Ammonia is also commonly transported by ship and by tube-trailer. Each is equipped with purpose-made storage vessels that mitigate the risks (corrosivity and toxicity) of ammonia.

NH₃ Storage and Distribution in the PICTs

- The PICTs may require only small volumes of ammonia depending on the end uses required. Horizontal cylindrical tanks can store small quantities of ammonia with ease, compared to spherical tanks. Pressurised or semi-refrigerated storage methods are most likely due to being more economically feasible compared to low-temperature storage technology.¹²³
- When comparing methods of distribution and their applicability within the PICTs, ammonia distribution via ship or tube-trailer is the more feasible compared to pipelines. These methods allow the distribution of small ammonia volumes and greater flexibility in final transport location. In the PICTs, ship and truck transport is used extensively for the distribution of goods.

4.3. Global Renewable Ammonia Market Status

Renewable ammonia projects are underway across the globe, primarily in regions with significant renewable energy resources (**Figure 20**).¹²⁵ China has many small projects that are in advanced stages of development, whilst larger projects are planned in regions including Australia, Africa, the Middle East, and the Americas. For example, the Yuri Renewable Hydrogen to Ammonia Project in Western Australia will produce 640 tonnes of green hydrogen per year as a zero-carbon feedstock for Yara's ammonia production facility, serving local and export markets.¹²⁶ Australia is aiming to become a key exporter of green hydrogen and derivatives to the Asia region, with potential for export to the PICTs region.



FIGURE 20. MAP OF ANNOUNCED PROJECTS FOR LOW-EMISSION AMMONIA PRODUCTION. IMAGE REPRODUCED FROM THE IEA UNDER THE TERMS OF THE CC BY 4.0 LICENSE.¹²⁵

4.4. Ammonia Use Cases in the PICTs

Hydrogen Carrier

Ammonia can solve challenges associated with the storage and distribution of hydrogen and has therefore been identified as an effective hydrogen carrier (a material, other than H_2 , that can be used to transport and store H_2). Ammonia is an effective hydrogen carrier due to ease of transformation to and from H_2 , ease of storage and distribution, and high volumetric energy density. If or when hydrogen is needed, the stored ammonia can be readily converted back to hydrogen via ammonia cracking (**Figure 21**). This process decomposes NH_3 in H_2 and N_2 . The hydrogen is purified, while the nitrogen is released into the atmosphere.⁵⁸

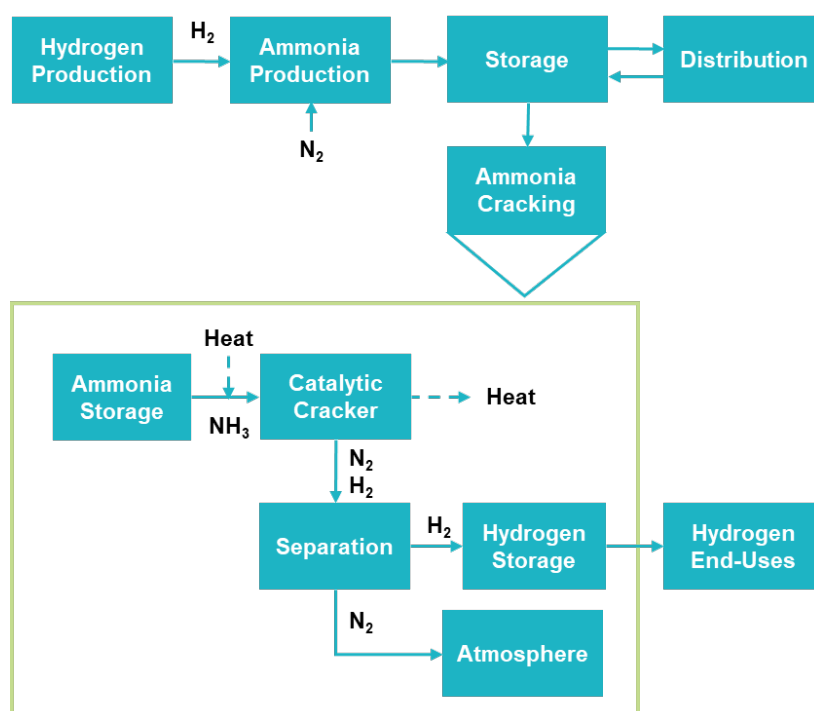


FIGURE 21. AMMONIA CRACKING PROCESS.

Ammonia cracking technology is essential for the conversion of ammonia to hydrogen; however, ammonia can also be used as a fuel or chemical precursor without conversion. Systems for ammonia cracking currently are at a low to medium TRL (3 – 4), and a low CRI, however technology improvements are underway (**Table 16**). Players in this space include Siemens Energy, Air Liquide, and Vortex Energy, each at the pilot scale with their ammonia cracking technologies in aims for decarbonising mobility and electricity generation sectors.^{127–129}

TABLE 16. TECHNICAL DATA OF PILOT SCALE AMMONIA CRACKING TECHNOLOGIES.^{127–129}

Technical Data				
Company	Siemens Energy	Air Liquide	Vortex Energy	Uniper
Type	Technology	Project	Technology	-
Production Rate	200 kg H ₂ per day	Industrial scale (pilot)	200 kg H ₂ per day	805 kg H ₂ per day
Separation Technology	Metal Membrane Technology	Catalytic cracking furnace	Ammonia cracker and membrane separator	-
Unit Cost	~ US \$4.3 million	-	-	-
Timeline	2024	2024	-	2030

Fertilisers

Around 75% of the ammonia produced globally is used as an intermediate for the synthesis of synthetic nitrogenous fertilisers, predominantly comprised of either urea or ammonium nitrate, synthesised by reacting ammonia with carbon dioxide and nitric acid respectively.

¹⁰⁷ Green ammonia can be integrated easily into already existing synthetic fertiliser production facilities.

In general, the PICTs do not import large volumes of fertilisers, however there is some domestic application. For example, South Pacific Fertilizers Ltd. imports bulk fertiliser blends base materials into NPK formulations, and packs and distributes to the local market in Fiji, particularly for sugar cane. Various blends of NPK are imported, as well as ammonium sulphate. **Table 17** details the imports of nitrogen-based products to the PICTs (including ammonia sulphate, ammonium nitrate, urea, and ammonia).

The ability to decentralise fertiliser production is a promising solution for reducing the import costs in remote or islanded communities. However, challenges exist with the high capital costs associated with small scale ammonia production (*discussed above*), the costs for further processing for fertiliser production, and the costs for transport of ammonia to islands or atolls that require the fertiliser. Further feedstock requirement needs must also be considered, for example, transforming ammonia into urea is contingent on the availability of CO₂. Additionally, pollution caused by excess nutrients from fertilisers is affecting marine ecosystems and coral reefs in the Pacific, which is highly likely to impact social acceptance of ammonia production for fertiliser use, which may result in the rejection of this pathway at scale.¹³⁰

TABLE 17. IMPORTS OF NITROGEN PRODUCTS (AMMONIA SULPHATE, AMMONIUM NITRATE, UREA, AMMONIA) IN THE PICTs FROM 2018 – 2022. MOST OF THESE NITROGEN-BASED PRODUCTS CAN BE USED FOR NITROGENOUS FERTILISERS.¹³¹

PICT	Imports of Nitrogen Products (tpa)
PNG	2327
Fiji	48.0
RMI	42.0
FSM	22.4
Palau	31.2
Tonga	21.5
Solomon Islands	24.0
Kiribati	1.2

Transport

Ammonia can be used as an alternative fuel, assisting in decarbonising the transportation sector. Ammonia is currently a leading contender to be deployed in the shipping industry,

whilst other applications include replacing carbon-emitting fuel in already existing internal combustion engines (with retrofitting), and power generation via ammonia fuel cells. The use of ammonia in marine engines displays several advantages, including a significant emissions reduction, infrastructure availability, and ease of operation. Disadvantages include the need for a pilot fuel due to the high ignition temperature of ammonia, as well as safety concerns, for example the difficulty in maintaining stringent safety standards due to frequent natural disasters in the region.¹³²

Internal combustion engines that run on ammonia are being developed for large-scale maritime applications. Three main players in the ammonia ICE space are Man Energy Solutions, Wartsila and IHI, which are all in the technology developmental stage (**Figure 22**). These two-stroke and four-stroke engines are expected to be commercialised around 2025.¹³³⁻¹³⁵



FIGURE 22. SOME AMMONIA ENGINES ARE IN DEVELOPMENT. IMAGES COURTESY OF THE MANUFACTURERS (WARTSILA, MAN ENERGY SOLUTIONS, AND IHI POWER SYSTEMS).

NH₃ as a Maritime Fuel in the PICTs

The international and domestic trade amongst the PICTs is heavily reliant on shipping. Due to the challenges in electrification in this sector, particularly for long-distance shipping, alternative fuels, such as renewable ammonia are targeted as a potential solution.

Ammonia bunkering stations could be strategically positioned along international or domestic trading routes, providing ships with low-carbon fuel. With a range of bunkering ports already in place within the PICTs,¹³⁶ most notably PNG and Fiji, and with the increase in trade between Australia and the Asia-Pacific region,¹³⁷ there is a significant opportunity to transition to low-carbon fuels, such as ammonia, in the PICTs region. Cruise traffic is also steadily increasing within the region, opening an opportunity for alternative shipping fuel.

However, the toxicity of ammonia may see its use limited to larger vehicles rather than short-sea, passenger, or inland waterway craft, as the use of ammonia will add significant complexity to ship design. Whilst renewable ammonia is currently cheaper to produce than renewable methanol, the vessel-related costs are higher for ammonia compared to methanol, and as such, methanol may be the “winner” in this space.¹²⁵

A further challenge is the supply requirements for ammonia-fuelled ships. It is estimated that one container ship would require around 60,000 tonnes of ammonia fuel per year.¹³⁸ Therefore, a small-scale facility, producing 50 – 300 tpd, would be insufficient for a deployment of a shipping fleet. Establishing a transition framework, for example, that

incorporates dual-fuel bunkering scenarios, could also be implemented to combat any supply challenges faced.

Overall, transitioning from conventional shipping fuels to ammonia within ships on both a domestic and international level will require significant collaboration between governments, shipping companies, port operators, the public, and other stakeholders.

Electricity Generation

Ammonia can also be used as a stationary fuel with the ultimate goal of replacing the use of fossil fuels, such as natural gas and diesel, in both industrial and domestic settings. When combusted, the bonds of ammonia are broken releasing only energy, water, and nitrogen. As the energy density of ammonia is relatively similar to conventional fuels, it shows promise for being incorporated into either existing or new power generation technologies, including in turbines, generators, and fuel cells. These types of technologies can be used in remote or islanded communities, for example as back-up electricity generators during natural disasters.

Gas turbines, which convert the fuel into mechanical energy and then electrical energy, can incorporate ammonia as fuel. Existing gas turbines can incorporate ammonia as a dual fuel, along with natural gas or kerosene, with limited retrofitting. Technology developers have also begun the development of gas turbines that are fuelled by 100% ammonia. Diesel generators are currently used for back-up power for many remote or islanded communities. Ammonia is a promising alternative fuel, especially in a dual fuel context for replacing diesel in generators. Direct ammonia fuel cells, although at the early stages of development, are promising technologies for stationary electricity generation, especially in a decentralised setting or for off-grid use.¹³⁹ Companies developing ammonia-based electricity generation technologies are outlined in **Table 18** below.

TABLE 18. AMMONIA-BASED ELECTRICITY GENERATION TECHNOLOGIES ARE CURRENTLY IN DEVELOPMENT.¹⁴⁰⁻¹⁴⁴

Technical Data						
Company	IHI	Mitsubishi Power	MAN Energy Solutions	Alma Clean Power	CSIRO	Gencell
Stationary Power Type	Gas Turbine	Gas Turbine	Two-stroke combustion engine	Solid Oxide Fuel Cell	Solid Oxide Fuel Cell	Cracker, hydrogen fuel cell
Application	Power generation	Small to medium-scale power stations for industrial applications Electricity generation for remote islands	Industrial Power Generation	Shipping mobility	Electricity generation	Decentralised Electricity generation
Electric and thermal efficiency	2 MW	40 MW	12 – 68 MW	61 – 67% (capacity = 6 kW)	>50%	-

Commercialisation Timeline	2023	2025	2024	-	2025	On the market
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A key challenge for the direct use of ammonia as a fuel is its high ignition temperature, requiring a pilot fuel for the first stage of engine ignition. As such, dual fuel solutions are the most feasible for the use of ammonia in combustion engines.

Ammonia combustion may also pose a risk of increased NO_x emissions. This challenge must be carefully considered by technology developers, ensuring measures are in place to minimise these emissions. For example, Mitsubishi's ammonia-fuelled gas turbine technology will implement a selective catalytic reduction, which targets the decomposition of NO_x that is released by the combustion of ammonia.

NH₃ as a Stationary Fuel in the PICTs

Heavy industries contribute significantly to the PICTs electricity consumption (see **Report A**), most notably in PNG and New Caledonia. With over 86% of New Caledonia's electricity consumption used by heavy industries and approximately 80% of fossil fuel origin (coal, fuel oil),¹⁴⁵ there is a significant opportunity to displace fossil fuels by implementing ammonia-fired gas turbines. For example, the implementation of a 40 MW ammonia-fired gas turbine system (such as technology being developed by Mitsubishi Power¹⁴⁴) could displace up to 500 tonnes of CO₂ per day.

Similarly, with generators running on diesel and heavy fuel oil being the main source of electricity generation within the PICTs, there is a significant opportunity for ammonia, for example in back-up electricity scenarios or in remote and islanded communities, ultimately leading to reduced costs and GHG emissions.

Challenges for the use of ammonia in the context of PICTs relate to its production and safety requirements. Land procurement is challenging due to the limited space availability to generate the scale of ammonia that would be needed to displace the fossil fuel plants. Furthermore, the high capital expense and production costs (*discussed above*) must be addressed to make the transition to green ammonia for stationary fuel in the PICTs a feasible option within the context of the PICTs. Ammonia must also be safely stored and transported due to its toxicity (*elaborated below*).

Figure 23 provides an overview of key ammonia technology providers for the above application areas.

NH ₃ Engines	Direct NH ₃ Fuel Cells	NH ₃ Cracking
  	  	  

FIGURE 23. COMMERCIAL AMMONIA TECHNOLOGY MANUFACTURERS. NOTE: THIS LIST IS NON-EXHAUSTIVE.

Summary of NH₃ Use in the PICTs

Table 19 highlights the applications, benefits, and development required for the main direct ammonia use cases relevant to the PICTs.

TABLE 19. AMMONIA END USE CASES IN THE PICTs.

Ammonia Derivative Applications	Description	Development required	Challenges	Benefits
Hydrogen/energy carrier	Ammonia is a promising solution to solving hydrogen's storage and distribution challenges. It is a liquid at a less negative temperature and has a relatively high volumetric energy density compared to hydrogen.	Higher TRL for ammonia cracking technologies is required.	Ammonia is toxic and requires numerous safety mechanisms.	Storage and transport to remote or islanded communities as a liquid. High volumetric energy density.
Fertiliser	Ammonia is used to produce nitrogen-based fertiliser. Decentralised green ammonia facilities could contribute to reducing fertiliser import costs within the PICTs.	Technology to produce fertiliser from ammonia is mature. However, further optimisation and system integration is required for small-scale, decentralised facilities.	High capital costs are currently associated with small-scale ammonia and fertiliser production facilities. Issues with fertiliser runoff.	No dependence on imported fertilisers
Fuel Applications	Description	Development required	Challenges	Benefits
Maritime transport	Ammonia is a promising alternative fuel for shipping. It can be blended with diesel or used as is. High TRL for storage and distribution in a maritime context. Particulate and SO _x emission reduction compared to traditional fuels.	Ammonia engines are in the early to mid-stages of development. Retrofitting of existing diesel engines to be applicable with ammonia is also in mid stages of development.	With ships requiring large fuel volumes and ammonia facilities in the PICTs most likely to be decentralised and small in scale, fuel demand for this application may be too high. Safety aspects of ammonia. May only apply to large ships.	Ammonia could provide emission-free shipping within the region or internationally, certainly for larger vessels, with prospects in regional boat operations.
Electricity Generation	Ammonia can be used as a back-up fuel either in diesel generators or ammonia fuel cells.	Existing diesel generators require retrofitting for ammonia to be used as a fuel. Ammonia fuel cells are still in the development stage, with a TRL of 4 – 7.	Existing diesel generators are required to be retrofitted or replaced to run on ammonia. Safety aspects of ammonia.	Ammonia is a promising diesel replacement, with ammonia-powered engines in development.

5. Renewable Methanol

For island nations aiming to decarbonise, renewable methanol presents a promising solution. Derived from sustainable sources including renewable electricity, captured CO₂, or biomass (**Figure 24**), this eco-friendly fuel offers a versatile approach to energy needs. Beyond its use as a clean fuel for maritime and land transport, or as a raw material for essential chemicals, methanol represents a convenient means for storing and distributing energy through conventional fuel infrastructure.¹⁴⁶ By tapping into existing networks, it provides an efficient pathway for power generation and bunker fuel for maritime and thermal applications, catering to local energy and heat demands. Thus, renewable methanol stands as a holistic strategy for island nations to transition seamlessly into a low-carbon future, while maximising infrastructure investments. The key challenge, as detailed further in this section, is the need for net-zero carbon sources in its production.

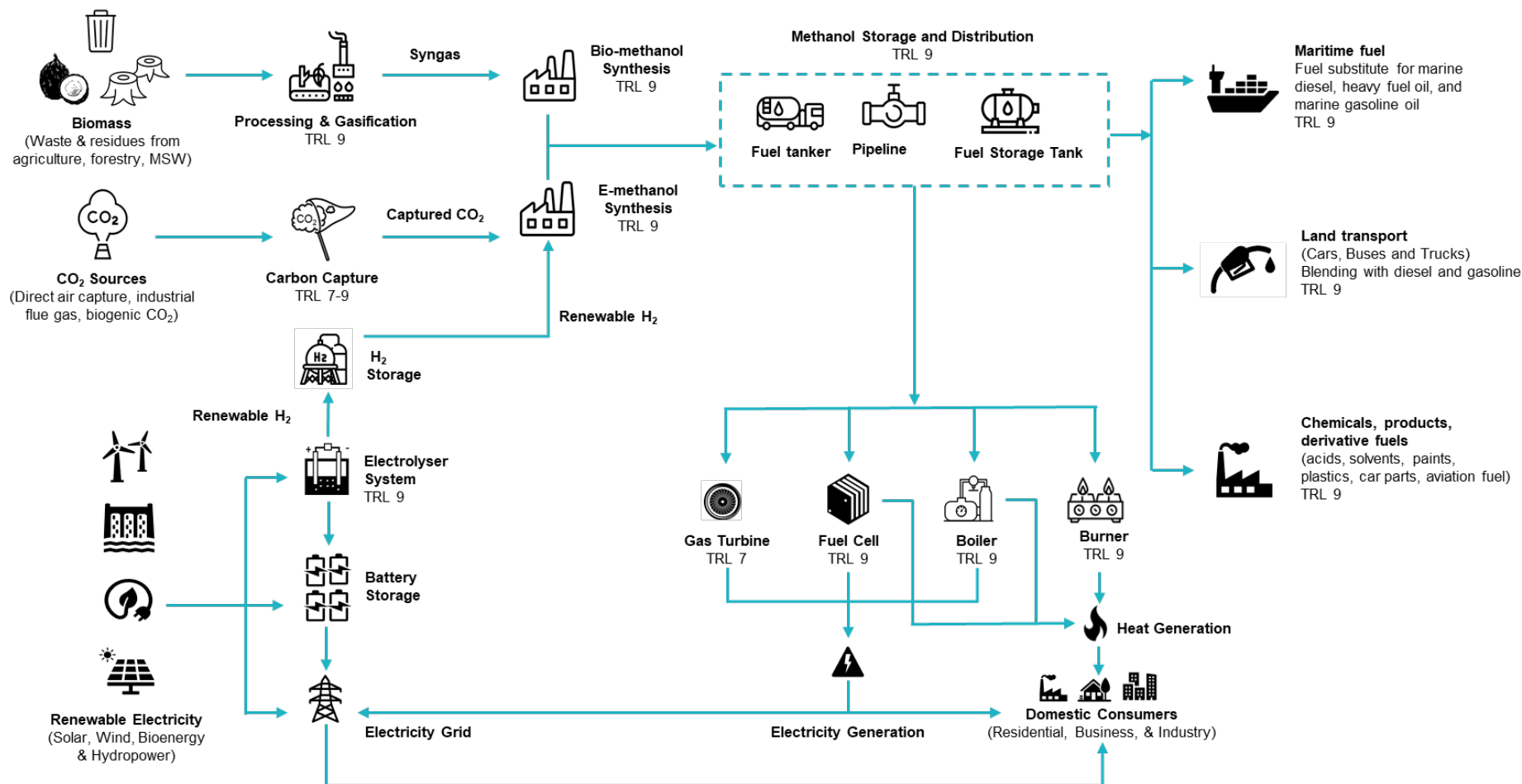


FIGURE 24. THE RENEWABLE METHANOL VALUE CHAIN. THE VALUE CHAIN COVERS PRODUCTION, STORAGE, DISTRIBUTION, AND APPLICATIONS. THESE ARE DISCUSSED IN THE FOLLOWING SECTIONS. THE TECHNICAL MATURITY OF THE TECHNOLOGY EMPLOYS THE CONVENTIONALLY USED TECHNOLOGY READINESS LEVEL INDEX.

Lifecycle Emissions of Carbon-based Renewable Fuels

Carbon accounting for renewable fuels (methanol, renewable diesel, and SAF) involves assessing the emissions produced throughout their lifecycle, from feedstock acquisition to production, use, and disposal. This comprehensive view ensures that the overall impact on the environment is quantified, enabling an accurate assessment and comparison of renewable fuel options.¹⁴⁷ A lifecycle assessment should consider:

Feedstock Acquisition and Transport: ¹⁴⁸

- Evaluation of the carbon footprint of obtaining raw materials, including the environmental benefits of using waste or by-products (e.g., reduced emissions from avoiding natural decomposition).
- Analysis of emissions from transporting these materials to the production facility.

Fuel Production Process:

- Measurement of energy consumption and emissions from the fuel production process.
- Consideration of the efficiency and environmental benefits of converting waste into fuel.

Distribution and Storage:

- Quantification of emissions associated with fuel transportation and storage.
- Assessment of fuel stability and potential environmental benefits from reduced reliance on fossil fuels.

End-Use Emissions:

- Calculation of emissions when the fuel is utilised, with emphasis on the comparative reduction in emissions compared to conventional fuels.
- Efficiency of engines using renewable fuels and their overall environmental benefits.

Disposal and Recycling:

- Analysis of emissions and impacts from the disposal or recycling of waste products.
- Evaluation of waste-to-energy processes and their role in reducing overall emissions.

Indirect Effects:

- Assessment of land use changes and their impact on the environment, including positive effects like reduced methane emissions from feedstock utilisation.
- Evaluation of impacts on water resources, biodiversity, and local communities.

Policy and Regulatory Framework: ¹⁴⁹

- Analysis of the impact of regulations on lifecycle emissions.
- Consideration of incentives or penalties related to environmental sustainability.

Comparative Analysis with Conventional Fuels: ¹⁵⁰

- Comparison of lifecycle emissions with traditional fossil fuels.
- Assessment of carbon footprint reduction and environmental benefits of renewable fuels.

5.1. Technology for Renewable Methanol Production

Bio-methanol Production via Gasification

Technologies that produce methanol from biomass, biogas, and Municipal Solid Waste (MSW) are well-established, leveraging traditional gasification and reforming processes akin to those used for methanol synthesis from coal or natural gas. **Figure 25** displays a commercial biomass to methanol plant from Sodra in Sweden, utilising biomass from forestry and paper pulp industries.



FIGURE 25. SWEDISH BIO-METHANOL PLANT CONVERTING FOREST AND PAPER PULP BIOMASS TO SUSTAINABLE FUEL.¹⁵¹

Figure 26 outlines the standard procedure for transforming biomass into methanol. In this process, a selected carbon feedstock is subjected to gasification at high temperatures, yielding syngas predominantly composed of carbon monoxide (CO) and hydrogen (H₂). The ratio of CO to H₂ in the syngas may vary based on the specific feedstock used. To adjust this ratio, the water gas shift (WGS) reaction is employed, or, if necessary, green hydrogen from external sources is integrated. Following this, the syngas interacts with a catalyst at moderate to high temperatures, leading to the formation of crude methanol, which is a mixture of methanol and water. Finally, through distillation, this crude methanol is refined to produce pure methanol.^{152–154}

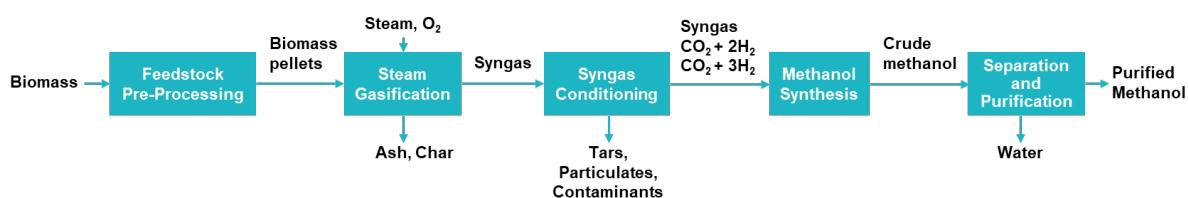


FIGURE 26. BIO-METHANOL PRODUCTION VIA GASIFICATION.

There exists significant potential for small-scale (10 – 100 tpd) decentralised bio-methanol production. Such localised production can efficiently harness diverse and readily available biomass resources, optimising energy independence and reducing infrastructure and transportation requirements, especially in remote or isolated regions.¹⁵⁵ The modular and scalable nature of this approach not only stimulates economic activity and innovation at

the local level, but also contributes to sustainable waste management, turning environmental liabilities into renewable energy assets. Waste management is a key issue in the Pacific, and as such government policy and regulation is critical to ensuring that the use of waste is carried out sustainably. This dual approach ensures a holistic development of bio-methanol infrastructure, catering to varied energy needs and geographical contexts.

Table 20 presents key process requirements and performance metrics for bio-methanol production via gasification including feedstock, energy, conversion efficiency, technology maturity, and emission reduction factor. Note, that these metrics were determined through a review of the literature followed by desktop calculations.^{156,157} Note that the carbon conversion efficiency is defined as the percentage of initial feedstock carbon content contained in the final product, and the conversion efficiency is defined as the energy content of the fuel product as a percentage of the total power and energy consumed during its production.

TABLE 20. PERFORMANCE METRICS: BIO-METHANOL PRODUCTION VIA GASIFICATION.

Feedstock requirement	Per tonne of methanol: <ul style="list-style-type: none"> ▪ Dry Bagasse: 2 t, or ▪ Woody biomass: 2 t, or ▪ MSW (RDF): 2 - 2.5 t
Energy demand	<ul style="list-style-type: none"> ▪ 0.05 MWh (per tonne of methanol)*
Conversion efficiency	<ul style="list-style-type: none"> ▪ 36% (carbon conversion)** ▪ 56% (primary energy conversion)***
TRL	<ul style="list-style-type: none"> ▪ 9
CRI	<ul style="list-style-type: none"> ▪ 2 – 3
CAPEX	<ul style="list-style-type: none"> ▪ US\$1,354 per tonne annual capacity
OPEX (including feedstock costs)	<ul style="list-style-type: none"> ▪ US\$63 per tonne methanol ▪ This equates to 6% of CAPEX
LCA GHG reduction vs. fossil methanol	<ul style="list-style-type: none"> ▪ Up to 95%

* Energy demand required for production, not including the energy content of biomass feedstock consumed.

** Carbon conversion efficiency is defined as the percentage of initial feedstock carbon content contained in the final product.

*** Primary energy conversion efficiency is defined as the final lower heating value of the fuel product as a percentage of the total power and energy consumed during its production. Excluding energy content of carbon feedstock.

E-methanol Production via Direct Hydrogenation of CO₂

E-methanol is produced through a power-to-liquid (PtL) pathway, converting recycled CO₂ into methanol using renewable energy (**Figure 27**).^{158,159} Deployment of e-methanol projects creates opportunities to increase renewable energy capacity in the PICTs, further strengthening energy security and potential renewable penetration in the region. In this approach, CO₂ is captured from the atmosphere or waste emissions (see **Report A** for more details), while hydrogen is produced via electrolysis using renewable energy (see **Section 3**).

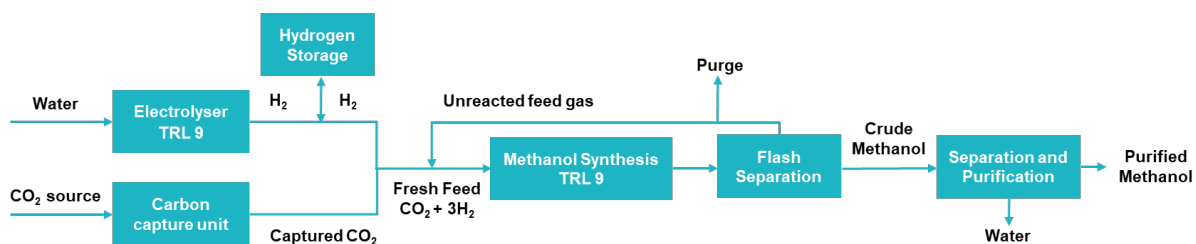


FIGURE 27. E-METHANOL PRODUCTION VIA DIRECT HYDROGENATION OF CO₂.

CO₂ and hydrogen are then directly reacted to create crude methanol (methanol + water), refined later through distillation. Direct CO₂ hydrogenation eliminates the need for conversion of CO₂ to CO, which reduces the number of process stages and energy required to prepare the feed. However, direct conversion of CO₂ has a lower single pass conversion, requiring a larger recycle ratio for high yields, impacting overall process efficiency (**Table 21**).¹⁶⁰

TABLE 21. PERFORMANCE METRICS: E-METHANOL PRODUCTION VIA DIRECT HYDROGENATION OF CO₂.

Feedstock requirement	Per tonne of methanol: <ul style="list-style-type: none"> CO₂: 1.4 t H₂: 0.2 t H₂O: 1.8 t (or kL)
Energy demand	<ul style="list-style-type: none"> 10 MWh (per tonne of methanol) Additional 1 – 2 MWh for carbon capture
Conversion efficiency	<ul style="list-style-type: none"> 95% (carbon conversion) 55% (primary energy conversion)
TRL	<ul style="list-style-type: none"> 9
CRI	<ul style="list-style-type: none"> 2 – 3
CAPEX	<ul style="list-style-type: none"> US\$1,387 per tonne annual capacity
OPEX (Including feedstock costs)	<ul style="list-style-type: none"> US\$1,011 per tonne methanol
LCA GHG reduction vs. fossil methanol	<ul style="list-style-type: none"> Up to 99%

Note: Costs assume direct air capture carbon source, with renewable energy costs included in OPEX.

The differences in the heat released by the hydrogenation reactions of CO and CO₂ lead to variations in the optimal reactor design. **Figure 28** showcases a water-cooled reactor design from MAN Energy, used in HIF's e-methanol plant in Chile.¹⁶¹

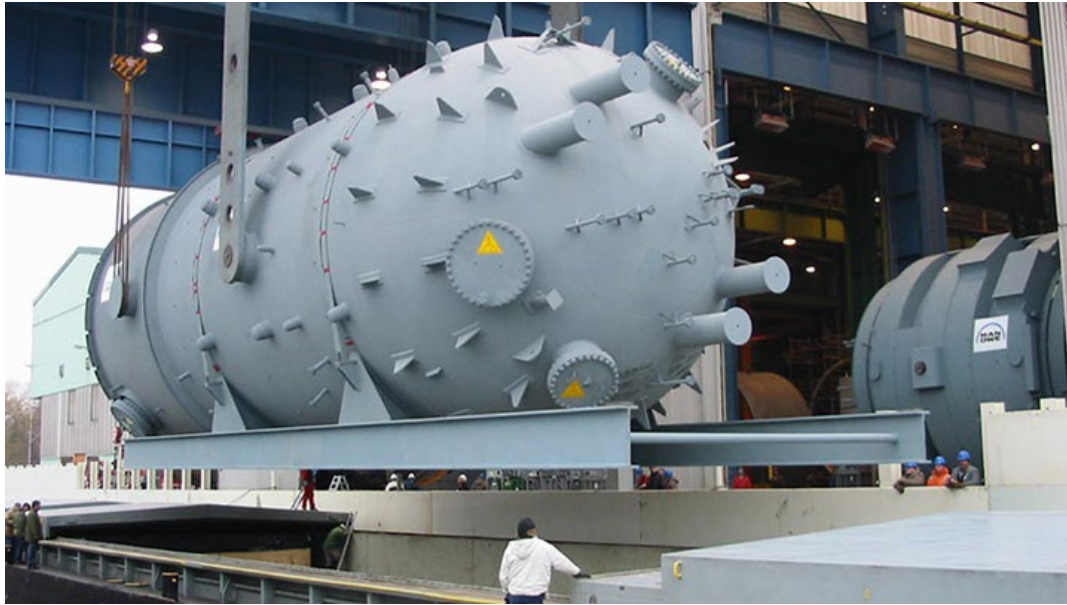


FIGURE 28. MAN ENERGY'S WATER-COOLED METHANOL SYNTHESIS REACTOR.¹⁶²

Decentralised, small-scale e-methanol production via direct CO₂ hydrogenation is a viable and innovative pathway, utilising captured CO₂ and renewable energy.^{159,163,164} The technology for producing methanol from syngas is mature and is predominantly optimised for large-scale operations, however, modifications to process configurations, have been considered to optimise the process for small-scale production. This approach is particularly advantageous in remote areas, minimising infrastructure and fostering energy independence. It stimulates local economic growth and offers carbon mitigation, presenting itself as a sustainable energy development solution, and aligning environmental sustainability with varying energy demands.

E-methanol Production via CO₂ Reduction and Hydrogenation of CO

E-methanol can be produced through an indirect CO₂ hydrogenation method as a part of the power-to-liquid (PtL) pathway, where recycled CO₂ is converted into methanol utilising renewable energy (**Figure 29**). In this adapted process, CO₂, captured from either the atmosphere or waste gas, is first reduced to CO.¹⁶⁵ Hydrogen, produced via renewably powered electrolysis, is then combined with CO to synthesise crude methanol, which can be further refined through distillation.

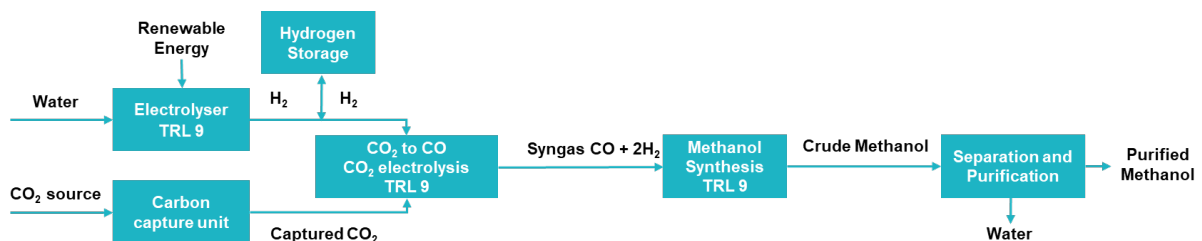


FIGURE 29. E-METHANOL PRODUCTION VIA CO₂ REDUCTION AND HYDROGENATION OF CO.

This indirect pathway mimics conventional methanol production, utilising syngas as a feedstock and requiring additional process stages and energy to convert CO₂ to CO before the methanol synthesis reaction, impacting the overall process efficiency due to the multiple stages involved (**Table 22**).¹⁶⁰

TABLE 22. PERFORMANCE METRICS: E-METHANOL PRODUCTION VIA DIRECT HYDROGENATION OF CO₂.

Feedstock requirement	Per tonne of methanol: <ul style="list-style-type: none">CO₂: 1.4 tH₂: 0.2 tH₂O: 1.8 t (or kL)
Energy demand	<ul style="list-style-type: none">10 – 15 MWh (per tonne of methanol)Additional 1 – 2 MWh for carbon capture
Conversion efficiency	<ul style="list-style-type: none">95% (carbon conversion)37 – 55% (primary energy conversion)
TRL	<ul style="list-style-type: none">9
CRI	<ul style="list-style-type: none">2 – 3
CAPEX	<ul style="list-style-type: none">US\$1,230 2023 per tonne annual capacity
OPEX (including feedstock costs)	<ul style="list-style-type: none">US\$1,259 2023 per tonne methanol
LCA GHG reduction vs. fossil methanol	<ul style="list-style-type: none">Up to 99%

Figure 30 showcases the eCOs system installation in Texas US developed by Topsoe, which employs a solid oxide electrolyser (SOEC) to convert CO₂ to CO.



FIGURE 30. TOPSOE CO₂ TO CO-ELECTROLYSIS TECHNOLOGY DEMONSTRATION.¹⁶⁶

Decentralised, small-scale e-methanol production via indirect CO₂ hydrogenation presents a valuable and innovative solution, leveraging captured CO₂ and renewable energy. The conventional technology for producing methanol from syngas is mature and is mainly optimised for large-scale productions; however, to facilitate small-scale applications, various modifications and adaptations to the process configurations are being explored.^{167,168} Such decentralised configurations are especially beneficial in isolated locations, reducing the need for extensive infrastructure and promoting energy autonomy. They contribute to local economic development and carbon reduction, acting as sustainable energy solutions that align environmental conservation with diverse energy requirements.

5.2. Methanol Production Technology Comparisons

The methanol production technologies under consideration reflect the imperative for sustainable and localised energy solutions within the PICTs. Bio-methanol via gasification makes practical use of readily available feedstocks such as biomass and waste, while e-methanol production, both through direct and indirect hydrogenation of CO₂, showcases the innovative use of renewable energy to reduce carbon footprints even further. Further, Waste-to-Energy (WtE) approaches could be implemented to generate renewable electricity to power e-methanol processes. The production methods are at a high technology readiness level, indicating their feasibility for immediate implementation. Decentralised production models for both pathways underscore the potential for bolstering energy independence and supporting local economies with minimal environmental impact.

Table 23 showcases a side-by-side comparison of the technology status and indicative costs and performance parameters. Note that these results are based on literature projections and are subject to change for the specific analysis of the PICTs.¹⁴⁶

TABLE 23. COMPARISON OF METHANOL PRODUCTION PATHWAYS.

Pathway	Bio-methanol	E-methanol
TRL	9	9
CRI	4	2 – 3
Cost*	Up to US\$770 per tonne	Up to US\$2,400 per tonne
Feedstocks	Water, O ₂ , Biomass (Agricultural waste and residues, forestry residues, municipal solid waste)	CO ₂ , H ₂ , H ₂ O, renewable energy
Carbon yield	36%	99%
Energy efficiency	56%	55%
Emissions intensity**	–55* to 40 gCO ₂ e /MJ	1 to 7 g CO ₂ e /MJ

* Costs are for scaled up plants at present.

** Including abatement of natural methane emissions through the use of manure feedstocks.

The cost of methanol production varies between production pathways and feedstock sources. The cost of bio-methanol is currently estimated between US \$320 – 770 per tonne compared to e-methanol which is between US \$800 – 2,400 per ton. However, e-methanol prices are expected to lower to US \$250 – 630 per tonne by 2050 with increased availability of low-cost renewable energy, as well as advances in conversion technology costs and scales.^{146,169}

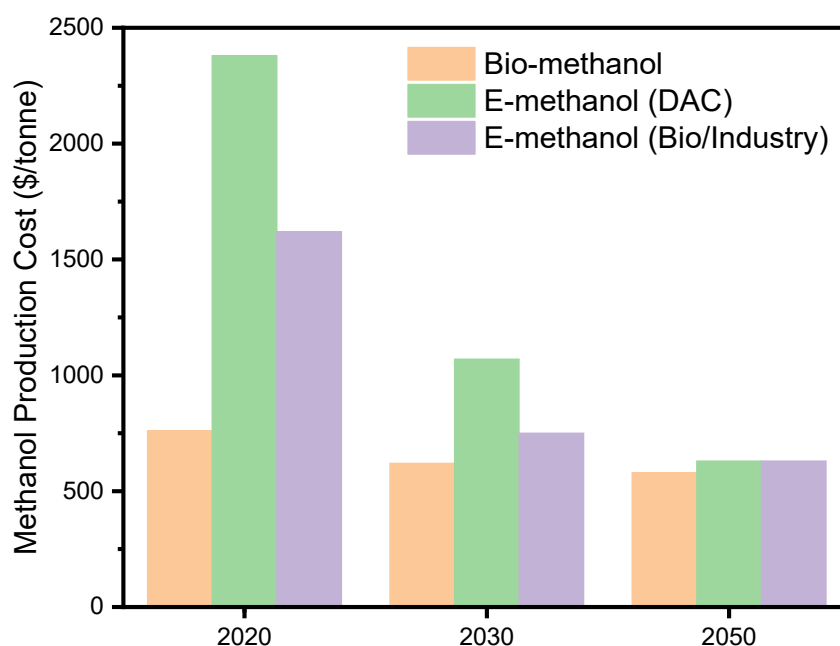


FIGURE 31. METHANOL PRODUCTION COST ANALYSIS. COST PROJECTIONS REPORTED DO NOT INCLUDE CARBON CREDITS. THESE RESULTS ARE BASED ON LITERATURE PROJECTIONS AND ARE SUBJECT TO CHANGE FOR THE SPECIFIC ANALYSIS FOR THE PICTs. ^{146,169}

5.3. Global Renewable Methanol Market Status

The global renewable methanol sector is expanding, with over 80 projects set to produce more than eight million tonnes of e-methanol and bio-methanol annually by 2027.¹⁷⁰ This expansion is a response to advancements in technology and increased government support, with individual plant capacities anticipated to rise from 5,000 – 10,000 to 50,000 – 250,000 tonnes per year within the next five years. This data underscores the accelerated development and commitment to renewable methanol as a key component in the transition to sustainable energy solutions. Key summaries of current and upcoming methanol projects are conveyed in **Figure 32**.

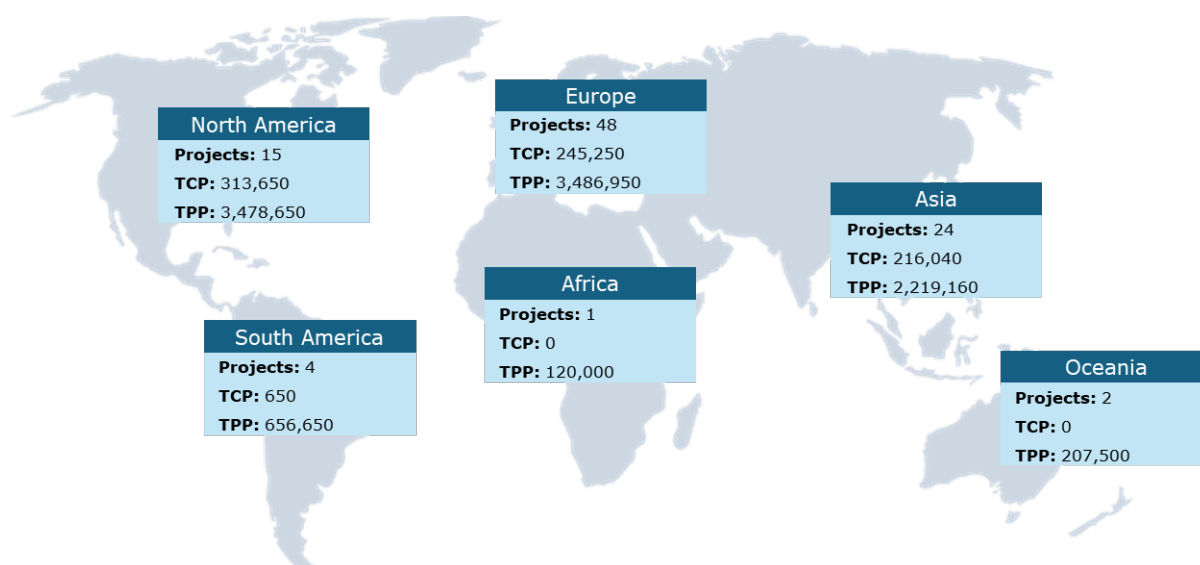


FIGURE 32. CURRENT AND UPCOMING GREEN METHANOL PROJECT MAP. NOTE: TCP; TOTAL CURRENT CAPACITY IN TONNES PER DAY. TPP; TOTAL PLANNED CAPACITY IN TONNES PER DAY.

In the Pacific region, several projects could potentially supply renewable methanol to the PICTs. For example, in Australia, ABEL is developing a green methanol plant to produce 300,000 tpa of methanol in Tasmania, Vast is developing a small-scale 7,500 tpa methanol plant in South Australia, and HAMR Energy plans to build a 200,000 tpa methanol plant in Victoria.¹⁷¹⁻¹⁷³ Australia is committed to becoming a global exporter of green hydrogen and derivatives. Other projects are planned in China, North America, and Singapore.^{174,175}

5.4. Methanol Use Cases in the PICTs

Renewable methanol is increasingly being recognised as a versatile alternative to conventional fossil fuels. Its liquid state at ambient conditions and high-octane number make it an attractive option for a variety of end-use cases, ranging from maritime and automotive transport to power generation and heating solutions.¹⁴⁶ The deployment of these technologies may benefit energy systems where traditional fuel logistics are complex and costly, as existing oil infrastructure can be used with minor modifications. Methanol's easier handling and storage requirements, coupled with its potential for local production from renewable sources, could lead to energy independence and significant reductions in greenhouse gas emissions. The use of methanol in such regions not only aligns with the global sustainability goals but also fosters resilience against the volatility of global fuel markets, a much-needed asset for these vulnerable communities.

Maritime Transport

Methanol's low environmental impact has made it a sought-after alternative for maritime fuel. It can significantly reduce emissions of sulphur oxides and particulate matter, two pollutants associated with traditional marine fuels. Development in this sector includes the adaptation of engines to run on methanol, with the added benefit of reducing toxicity to marine life, highlighting the potential of renewable methanol's to contribute to cleaner oceans, a priority amongst the PICTs.¹⁷⁶⁻¹⁷⁹

Methanol-powered engines for maritime vessels are available and have been a key driver for the deployment of green methanol projects. Notably, Maersk has launched the world's first green methanol-powered shipping vessel, with a fleet of six additional methanol vessels on order from Yangzijiang Shipbuilding Group.¹⁸⁰ Companies including Wärtsilä, MAN Energy Solutions, and the Anglo Belgian Corporation have pioneered the development of methanol-fuelled engines (**Figure 33**).



FIGURE 33. SOME METHANOL ENGINES AVAILABLE FOR MARITIME APPLICATIONS. IMAGES SOURCED FROM THE MANUFACTURERS (MAN ENERGY, WARTSILA, AND ANGLO BELGIAN CORPORATION).

These developments are critical for the widespread adoption of methanol in industries and transport. Some other key players and developers of methanol end use technologies are listed in **Figure 34**.

Upcoming innovations set to enhance the methanol landscape include:

- Rolls Royce is working with manufacturer Woodward L'Orange and research institute Wissenschaftlich-Technisches Zentrum Roßlau (WTZ Roßlau) to develop a concept for a high-speed internal combustion engine for ships that can run on green methanol by 2025.¹⁸¹
- Swiss marine power company WinGD and Korean engine builder HSD Engine have initiated a Joint Development Project (JDP) to advance the development of WinGD's methanol-fueled big-bore engines. The aim is to deliver an engine capable of running on carbon-neutral green methanol by 2024.¹⁸²
- Japanese engineering company Hitachi Zosen plans to develop technology to convert ship engines to run on green methanol, aiming to tap into rising demand for cleaner shipping fuels driven by the industry's push for decarbonisation. Hitachi Zosen will work on the technology with Germany's Man Energy Solutions.

Methanol Fuel Cells	Methanol Boilers	Methanol Shipping
  		   
Methanol high performance vehicles	Methanol Cars and Trucks	Methanol to chemicals, fuels, and materials
 		  

FIGURE 34. METHANOL END-USE KEY DEVELOPERS. NOTE: THIS LIST IS NON-EXHAUSTIVE.

Power Generation

Direct Methanol Fuel Cells (DMFCs) and Reformed Methanol Fuel Cells (RMFCs) are technologies that convert methanol into electrical energy. These fuel cells enable deployment as stationary power sources and mobile applications like electric vehicles. The properties of methanol as a liquid fuel make these fuel cell systems a convenient and simple replacement for diesel generator applications, meaning that much of the diesel distribution networks could be utilised and repurposed for methanol storage and distribution.

Direct and reformed methanol fuel cell technologies have been commercialised and are offered by several developers and suppliers. This includes (4 kW) systems such as those offered by Advent, and Blue World Technologies suitable for microgrid and decentralised settings.^{183,184} This scale can be used to replace small-scale diesel generators for mining equipment (drilling equipment etc.) or services like heating, water pumps, etc. Smaller systems in the range of 40 – 125 W such as those offered by SFC Energy could also fill the role of mobile and small stationary power systems across a range of sectors requiring remote or backup power supplies (**Figure 35**).¹⁸⁵



FIGURE 35. METHANOL FUEL CELL AND BOILER TECHNOLOGIES FOR POWER AND HEAT APPLICATIONS. IMAGES SOURCED FROM MANUFACTURERS (BLUE WORLD TECHNOLOGIES, ADVENT TECHNOLOGIES, SFC ENERGY, AND ALFA LAVAL AALBORG).

Automotive Transport

The automotive industry has also looked into methanol as a viable option. Methanol can be utilised in internal combustion engines with modifications and presents a cleaner-burning alternative to gasoline and diesel, reducing urban air pollution when integrated into road transport systems. Methanol can also be blended with petrol and diesel for use in existing vehicles.¹⁴⁶ As discussed in **Report A**, methanol-powered vehicles have seen recent interest, including the Geely Emgrand 7 cars and the Volvo DME-fuelled truck, whilst Swedish cars have been powered by a combination of methanol (56%) and gasoline (44%).¹⁴⁶ China is developing its M100 (100% methanol) fuel, and methanol-derived fuels such as A20, a 15% methanol and 5% bioethanol blend, are being trialled in Italy.¹⁸⁶

Derivative Fuels

Methanol also serves as a precursor for the synthesis of other forms of clean energy, such as dimethyl ether (DME), synthetic gasoline, and jet fuel. This adaptability allows methanol to seamlessly integrate into the existing energy infrastructure and broaden its utility across different sectors, as renewable methanol is chemically identical to fossil-derived methanol.^{187–189}

Opportunities and Challenges for Methanol in the PICTs

In the Pacific Island Countries and Territories (PICTs), there are huge opportunities for methanol to immediately decarbonise the regional economy, especially hard-to-abate sectors such as small-scale energy generation and maritime transportation. These applications in the PICTs are described in **Table 24**. Further, methanol has potential for utilisation in mining sectors in the region. There are a large number of potential offtakers that may seek to procure alternative fuels such as methanol or renewable diesel to reduce fossil diesel consumption, including Societe Minere de Sud Pacifique (New Caledonia), Dome Gold Mines (Fiji, PNG), Vatukoulia Gold Mines (Fiji), Lion One Metals Limited (Fiji), Ok Tedi Copper and Gold Mine (PNG), and Lihir Gold Mine (PNG).

Despite the potential, several challenges exist for methanol in the PICTs. The theoretical feedstock availability for methanol production (both biomass and waste CO₂ sources) in the region is relatively limited. There is also the concern of potential land competition for growing dedicated energy crops. Moreover, the region lacks the necessary infrastructure to support the entire methanol value chain. However, with methanol projects emerging across Europe, Asia, Australia, and America, the PICTs could consider sourcing methanol from neighbouring regions. A large proportion of maritime activities in the Pacific consists of small to medium-sized vessels, however, modification/retrofitting of engines in these vessels may not yet be available and could be infeasible for local owners and operators.

Table 24 highlights the applications, benefits, and development required for the main direct methanol use cases relevant to the PICTs.

TABLE 24. METHANOL END USE CASES IN THE PICTs.

Power Applications	Description	Development required	Benefits
Telecommunication	Methanol can be used for power generation directly through fuel cell technology. These methanol fuel cells have been utilised by telecommunications operators as a backup power source in regions with limited and unstable power networks.	Methanol fuel cells for stationary power applications are a mature technology that can be integrated into existing telecommunication systems.	Storage as a liquid in fuel tanks is simple, stable, and easily distributed. As a commodity, this may be more easily managed and implemented compared to battery storage and hydrogen energy storage. Methanol is also odourless, does not produce fumes and is less environmentally harmful compared to spills of other fuels.
Local generators	Methanol fuel cells can serve as backup power for local communities and even households during periods of grid instability.	Methanol fuel cells for stationary power applications are a mature technology. Integration of methanol fuel cells could coincide with and complement the installation of rooftop solar.	
Grid backup	Methanol can also be used to generate heat and steam in industrial boilers. Which can be combined with gas turbines to generate power on a larger scale such as for grid backup.	New infrastructure and equipment are required.	
Fuel Applications	Description	Development required	Benefits
Maritime transport	Methanol is a prime candidate as an alternative to heavy fuel oil (diesel bunker fuel) to fuel maritime vessels. Key drivers include increasing restrictions on SO _x , NO _x and particulate matter emissions from maritime activity around emission control areas (ECAs), and emission reduction targets	Requires methanol engine, or modified diesel engine for direct use. Methanol has less than half the volumetric energy density of HFO. Adjustments to tank size are required for a similar range.	Less toxic to marine life than diesel or other shipping fuels Sulphur free Soot free Almost no particulate matter Odourless No fumes Low NO _x emissions Up to 99% reduction in net lifecycle GHG emissions
Automotive transport	Methanol can be blended with diesel and gasoline for direct use in internal combustion engines. Pure methanol	Methanol has about half the volumetric energy density of gasoline and diesel. Adjustments to tank size are required for a similar range.	

	can be used in modified diesel engines.		
Heating	Methanol can be used to generate heat and steam in industrial boilers.	New infrastructure and equipment are required.	
Methanol burners	Being free of odour and fumes, methanol is suitable for use in domestic burners.	New infrastructure and equipment are required.	
Methanol derivative fuels use cases			
Methanol to DME	Methanol conversion to Dimethyl ether. DME can replace LPG applications. Up to 20% blending of DME with LPG can be used with no – very limited modifications to existing equipment.	Industrial LPG equipment may need modification to run on pure DME.	DME replacing LPG usage in households.
Methanol to Gasoline (MTG)	Methanol to gasoline conversion enables for complete substitution in internal combustion engines.	Cost effective methanol to gasoline technology	Direct substitution without modification to engines or tank volumes.
Methanol to Jet fuel (MtJ)	Methanol to jet fuel conversion	MtJ process has yet to be approved by major aviation standards.	Enabling economies of scale for methanol production and demand.

6. Sustainable Aviation Fuel and Renewable Diesel

Sustainable aviation fuel (SAF) and renewable diesel are key to decarbonising aviation and heavy-duty transportation at scale and speed, achieving net zero carbon emissions by 2050. SAF and renewable diesel are produced from sustainable feedstocks such as waste or purposefully grown biomass and captured or waste CO₂ emissions (**Figure 36**). SAF and renewable diesel can reduce lifecycle carbon emissions by up to 80% compared to traditional jet fuel,¹⁹⁰ whilst renewable diesel has a 65% lower carbon emission intensity compared to conventional diesel.¹⁹¹ Importantly, SAF and renewable diesel are safe to use in existing engines and infrastructure.

6.1. Technology for SAF & Renewable Diesel Production

There are many pathways to produce SAF and renewable diesel. These conversion technologies can transform a wide range of biomass and waste feedstocks, including CO₂, into these synthetic fuels. This section focuses on four SAF and renewable diesel production pathways that are expected to achieve significant scalability and garner industry attention. Hydrotreated Esters and Fatty Acids (HEFA), Alcohol-to-Jet (AtJ), and Gasification-Fischer-Tropsch (GFT) are categorised as biogenic pathways, whilst Power-to-Liquid (PtL) is classified as an electrofuel production pathway. **Table 25** describes the definition, feedstock, opportunities, and challenges for each pathway.

TABLE 25. SAF AND RENEWABLE DIESEL TECHNOLOGY PATHWAYS AND ASSESSMENT OF OPPORTUNITIES AND CHALLENGES BASED ON FEEDSTOCK AND TECHNOLOGY MATURITY.^{192–194}

	HEFA	AtJ	GFT	PtL
Description	Hydro-processing of oils and fats to produce diesel fuel.	Catalytic conversion of alcohol to produce jet fuel.	Conversion of biomass into synthetic gas then fuel.	Combining renewable electricity with CO ₂ and water to produce H ₂ .
Feedstock	Waste and residue lipids, purposely grown oil energy plants.	Agricultural and forestry residues, municipal solid waste, purposely grown cellulosic energy crops.	Agricultural and forestry residues, municipal solid waste, purposely grown cellulosic energy crops.	CO ₂ , water, and renewable electricity.
Opportunities	Safe, proven, and scalable.	Potential in mid-term, capital-light.	Potential in mid-term, relatively higher blend rates possible (50%).	Abundant feedstocks and likely the cleanest fuel type possible.
Challenges	Feedstock availability and vulnerability to supply chain shocks.	High opportunity cost to sell ethanol for road transport.	Feedstock availability and vulnerability to supply chain shocks.	Energy-intensive to produce, dependent on renewable electricity production and captured carbon availability.

Definition of SAF and Renewable Diesel

- In this report, SAF is defined as an alternative aviation fuel derived from sustainable non-petroleum feedstock, to serve as a drop-in replacement fuel for fossil-derived aviation fuel. SAF can be produced via biogenic pathways (bio-SAF) or e-pathway (e-SAF). Bio-SAF is made from biomass feedstock including, but not limited to, municipal solid waste, lignocellulosic biomass, or fats/greases/oils, whilst e-SAF is made from CO₂ captured at emission points or from atmosphere, and renewable electricity.
- In this report, renewable diesel is defined as an alternative diesel fuel derived from sustainable non-petroleum feedstock to serve as a drop-in replacement fuel for fossil-derived diesel. Renewable diesel can be produced via biogenic pathways (bio-diesel) or e-pathways (e-diesel). Bio-diesel refers to renewable diesel derived from biomass feedstock (e.g., municipal solid waste, lignocellulosic biomass, or fats/greases/oils) but different from fatty acid methyl ester (FAME) biodiesel, in that it only contains hydrogen and carbon, making it a hydrocarbon fuel just like petroleum diesel. On the other hand, e-diesel is renewable diesel produced from CO₂ captured at emission points or from atmosphere, and renewable electricity.

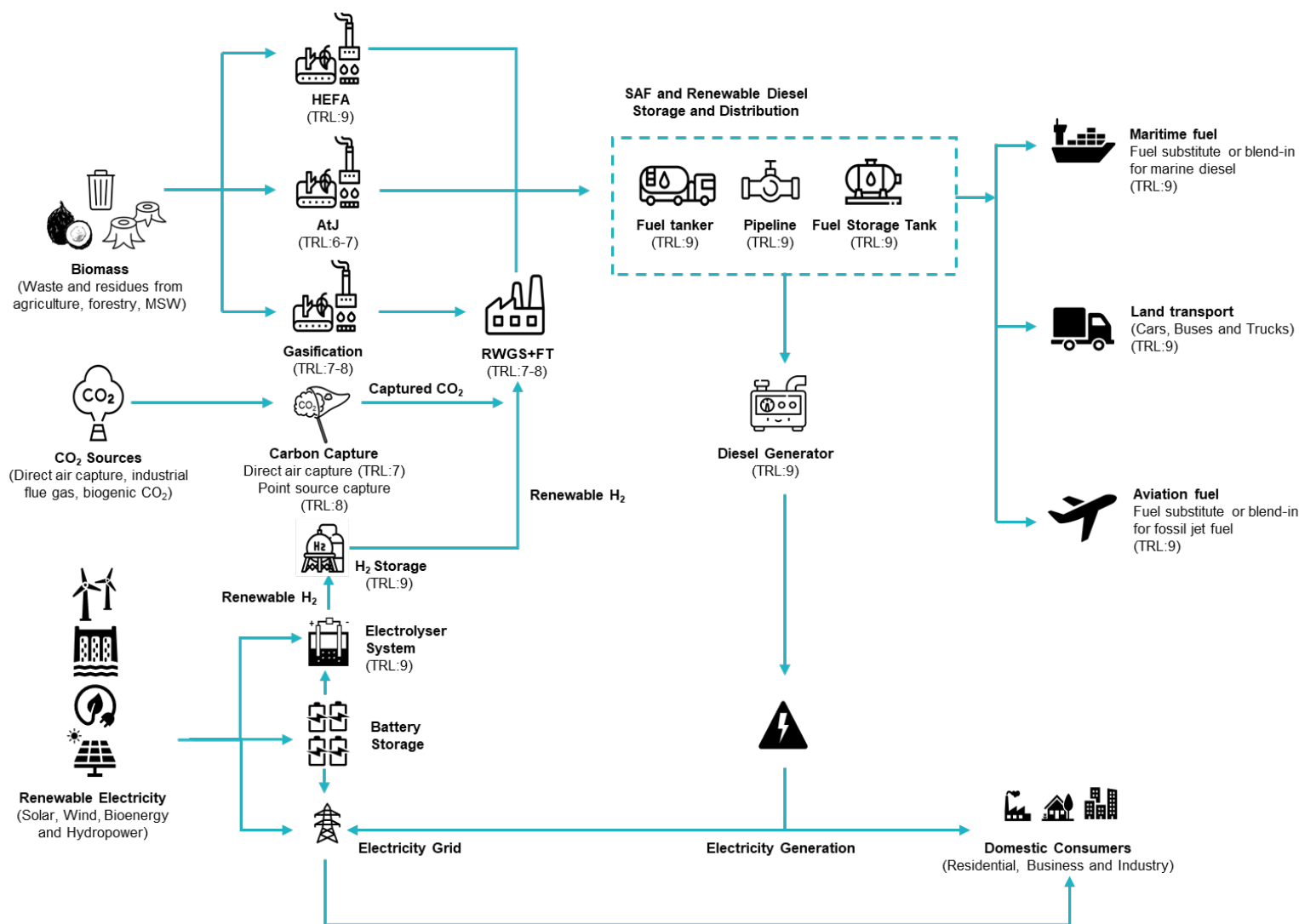


FIGURE 36. SAF AND RENEWABLE DIESEL VALUE CHAIN. THE VALUE CHAIN IS DISTRIBUTED INTO PRODUCTION, STORAGE, DISTRIBUTION, AND APPLICATIONS. THE VALUE CHAIN COVERS PRODUCTION, STORAGE, DISTRIBUTION, AND APPLICATIONS. THESE ARE DISCUSSED IN THE FOLLOWING SECTIONS. THE TECHNICAL MATURITY OF THE TECHNOLOGY EMPLOYS THE CONVENTIONALLY USED TECHNOLOGY READINESS LEVEL INDEX.

Hydrotreated Esters and Fatty Acids (HEFA)

HEFA is a safe, proven, and scalable pathway that proceeds via the hydro-processing of oils and fats to produce jet fuel and diesel (**Figure 37**). Several feedstocks suitable for HEFA include waste and residue lipids, as well as purposely grown oil trees.

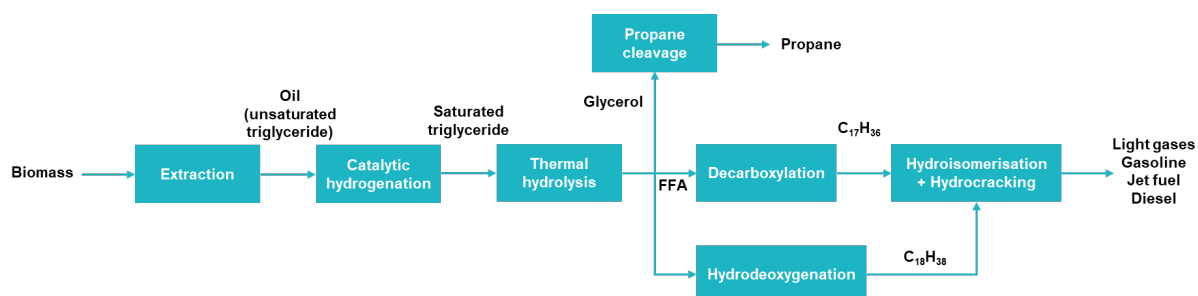


FIGURE 37. THE HEFA PROCESS.¹⁹⁵ NOTE: FFA ARE FREE FATTY ACIDS.

HEFA conversion can reach a carbon conversion efficiency of 90% and an energy conversion efficiency of 76%, significantly higher compared with other biomass-to-liquid routes.^{193,196} The yields to total output of hydrocarbons are 46% jet fuel and 46% road fuel including gasoline and/or diesel. In terms of technology and commercial readiness, the TRL and CRI of the HEFA conversion route are considered high (9 and 4, respectively), rendering HEFA to be among the few advanced biofuels with near commercial fuel readiness level (**Table 26**). Compared to fossil jet fuel, HEFA offers a GHG emission saving potential of 75 – 84%, with further reduction potential if green hydrogen is used in the hydro-processing step.¹⁹³ Nevertheless, HEFA suffers from numerous key challenges including feedstock availability and vulnerability to supply chain shocks.

TABLE 26. KEY TECHNOLOGICAL AND ENVIRONMENTAL PERFORMANCE METRICS OF THE HEFA PROCESS.¹⁹³

Carbon conversion*	▪ 90%
Energy conversion**	▪ 76%
Yields (optimised for SAF)	▪ 46% jet fuel + 46% road fuel (gasoline/diesel)
TRL	▪ 9
CRI	▪ 4
CAPEX	▪ ~ US\$100 per tonne of fuel
OPEX (including feedstock cost)	▪ ~ US\$1,300 per tonne of fuel
LCA GHG reduction vs. fossil jet	▪ 75 – 84%

* Carbon conversion is defined as the proportion of the biomass carbon that ends up in FT fuels.

** Energy conversion is defined as the ratio between the input energy and output energy in FT fuels reflected by the lower heating values (LHVs).

Neste NexBTL in Singapore produces synthetic fuels, including SAF and renewable diesel, from waste and residue raw materials, including animal waste fat, used cooking oil, and residue streams from the vegetable oil industry.¹⁹⁷ Singapore refinery's total production capacities are 2.6 million tonnes of synthetic fuels per annum, including 1 million tonnes of SAF and 1.6 million tonnes of diesel.



FIGURE 38. NESTE'S OIL REFINERY IN SINGAPORE.

Alcohol-to-Jet (AtJ)

AtJ is the catalytic conversion of alcohol into jet fuel and diesel. The ethanol route demonstrates strong potential in the mid-term, with pilot demonstration projects now being developed. Several feedstocks are suitable for this pathway, including biomass that can be converted into ethanol, for example, agricultural and forestry residues, municipal solid waste, and purposely grown cellulosic energy crops (**Figure 39**). In the Pacific, Fiji has historically produced sugarcane, however the industry is challenged by economies of scale amongst other issues. The AtJ pathway could revive such industries across the PICTs.

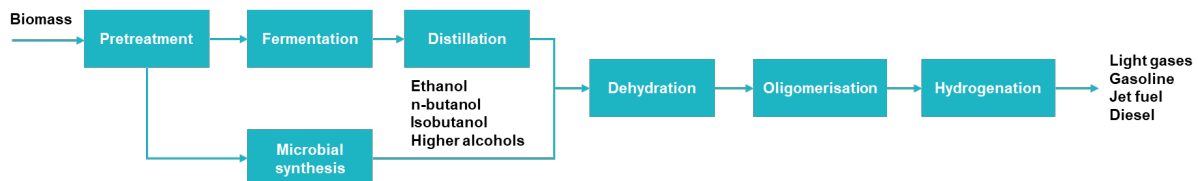


FIGURE 39. THE AtJ PROCESS.¹⁹⁵

The AtJ conversion pathway has a carbon conversion efficiency of 16% and an energy conversion efficiency of 95%.¹⁹⁸ The yields to the total output of hydrocarbons (optimised for SAF production) are 77% jet fuel and 6% road fuel including gasoline and/or diesel.¹⁹³ In terms of technology and commercial readiness, the TRL and CRI of the HEFA conversion route are considered high (6 – 7 and 3, respectively), indicating that further technological improvements are required to be commercially viable. Compared to fossil jet fuel, AtJ offers a GHG emission saving potential of 85 – 94% (**Table 27**).¹⁹³

In addition to the ethanol pathway, methanol-to-jet has also gained traction where bio- or e-methanol serves as an intermediate for jet fuel synthesis. ExxonMobil has developed this technology to convert methanol from the gasification of biomass and waste or captured CO₂ into SAF.¹⁹⁹ However, AtJ suffers from a critical challenge given ethanol is produced today as a road gasoline blend and chemical feedstock, competing as outlets for sustainable biomass.

TABLE 27. KEY TECHNOLOGICAL AND ENVIRONMENTAL PERFORMANCE METRICS OF ATJ PROCESS.¹⁹³

Carbon conversion	▪ 16%
Energy conversion	▪ 95%
Yields (optimised for SAF)	▪ 77% jet fuel + 6% road fuel (gasoline/diesel)
TRL	▪ 6-7
CRI	▪ 3
CAPEX	▪ ~ US\$1,200 per tonne of fuel
OPEX (including feedstock cost)	▪ ~ US\$1,200 per tonne of fuel
LCA GHG reduction vs. fossil jet	▪ 85 – 94%

LanzaJet Freedom Pines Fuels in Georgia is the world's first ethanol-to-jet production plant (**Figure 40**).²⁰⁰ The facility will produce 10 million gallons of SAF and renewable diesel per year from ethanol, using a range of sustainable, low-carbon intensity ethanol, including from waste feedstocks. This plant is expected to complete construction and begin its commissioning in 2023.

**FIGURE 40.** LANZAJET'S FREEDON PINES FUELS IN GEORGIA.

Gasification and Fischer-Tropsch (GFT)

GFT is the conversion of biomass into syngas (a mixture of carbon monoxide and hydrogen) via gasification, followed by the Fischer-Tropsch conversion into liquid fuels (**Figure 41**). The H₂:CO ratio in the syngas has a profound effect on the hydrocarbon product distribution. Feedstocks suitable for GFT include agricultural and forestry residues, municipal solid waste, and purposely grown cellulosic crops. The pathway, now in the pilot stage, has significant potential in the mid-term.



FIGURE 41. THE GFT PROCESS.¹⁹⁵

The GFT conversion pathway has a carbon conversion efficiency of 41% and an energy conversion efficiency of 51%.²⁰¹ The yields to the total output of hydrocarbons (optimised for SAF production) are 60% jet fuel and 22% road fuel including gasoline and/or diesel. In terms of technology and commercial readiness, GFT is considered a mature technology with TRL and CRI of 7 – 8 and 3, respectively.¹⁹³ Compared to fossil jet fuel, GFT offers a GHG emission saving potential of 85 – 94% (**Table 28**).¹⁹³

Nevertheless, GFT suffers from numerous key challenges including feedstock availability and vulnerability to supply chain shocks.

TABLE 28. KEY TECHNOLOGICAL AND ENVIRONMENTAL PERFORMANCE METRICS OF GFT PROCESS.¹⁹³

Carbon conversion	▪ 41%
Energy conversion	▪ 51%
Yields (optimised for SAF)	▪ 60% jet fuel + 22% road fuel (gasoline/diesel)
TRL	▪ 7 – 8
CRI	▪ 3
CAPEX	▪ ~ US\$1,600 per tonne of fuel
OPEX (including feedstock cost)	▪ ~ US\$300 per tonne of fuel
LCA GHG reduction vs. fossil jet	▪ 85 – 94%

In France, Thyssenkrupp is working on the next generation of BioTfuel (**Figure 42**).²⁰² This project aims to achieve the conversion of lignocellulosic biomass into SAF and renewable diesel via entrained flow gasification and Fischer-Tropsch technologies. It is envisaged that commercial-scale BioTfuel will have a capacity of up to 5,000 barrels per day. The demonstration has been conducted successfully in Venette and Dunkirk.



FIGURE 42. THYSSENKRUPP'S BIOTFUEL PROJECTS IN VENETTE AND DUNKIRK.

Power-to-Liquid (PtL)

PtL involves the production of syngas via either a reverse water gas shift reaction (RWGS) between captured CO₂ and green hydrogen from water electrolysis or a direct co-electrolysis set up with a solid oxide electrolyser driven by renewable electricity. Consecutively, the conversion of syngas into liquid fuels is achieved by a Fischer-Tropsch process (Figure 43).

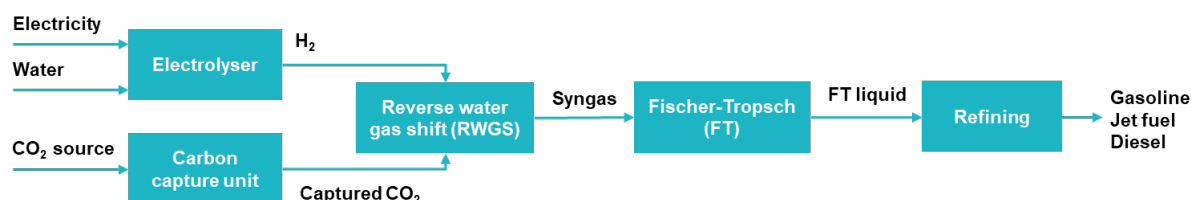


FIGURE 43. THE PTL PROCESS.¹⁹⁵

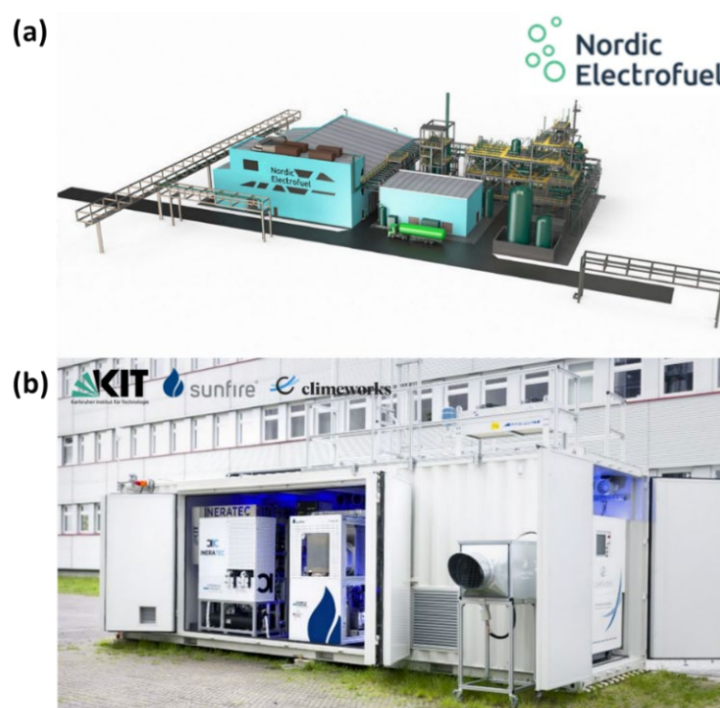
PtL has a carbon conversion efficiency of 88% and an energy conversion efficiency of 63%.²⁰³ The yields to the total output of hydrocarbons (optimised for SAF production) are 60% jet fuel and 22% road fuel including gasoline and/or diesel.¹⁹³ In terms of technology and commercial readiness, PtL is still at the development stage towards commercialisation with TRL and CRI of 5 – 6 and 2, respectively. Compared to fossil jet fuel, PtL offers a GHG emission saving potential of up to 99% regardless of the CO₂ alternative used (industrial emission point or direct air capture) (Table 29).¹⁹³

Nevertheless, PtL is energy-intensive and highly dependent on renewable electricity production and captured carbon availability.

TABLE 29. KEY TECHNOLOGICAL AND ENVIRONMENTAL PERFORMANCE METRICS OF THE PTL PROCESS.¹⁹³

Carbon conversion	▪ 88%
Energy conversion	▪ 63%
Yields (optimised for SAF)	▪ 60% jet fuel + 22% road fuel (gasoline/diesel)
TRL	▪ 5 – 6
CRI	▪ 2
CAPEX	▪ ~ US \$2,000 per tonne of fuel
OPEX (including feedstock cost)	▪ ~ US \$1,900 per tonne of fuel
LCA GHG reduction vs. fossil jet	▪ 99%

Nordic Electrofuel utilises renewable electricity, hydrogen, and CO₂ to produce SAF and renewable diesel (**Figure 44**).²⁰⁴ The first plant is located at Herøya Industrial Park in Porsgrunn, Norway. The plant is named E-fuel 1 and is designed for a yearly production capacity of 10 million litres of synthetic fuels. Nordic Electrofuel’s technology involves green hydrogen production from electrolysis as well as RWGS and FT processes. In addition, an integrated PtL test facility to synthesise fuels from the air-captured CO₂ has been demonstrated by the partners of the P2X Kopernikus project led by Karlsruhe Institute of Technology (KIT).²⁰⁵ The facility combines Climeworks’ direct air capture technology, Sunfire’s CO₂ electrolyser, as well as KIT’s Fischer-Tropsch and hydrocracking processes.

**FIGURE 44.** EXAMPLES OF COMMERCIAL ELECTROFUEL PRODUCTION FACILITIES. **(A)** PLANNED NORDIC ELECTROFUEL PLANT AT HERØYA INDUSTRIAL PARK IN PORSGRUNN, NORWAY. **(B)** AN INTEGRATED PTL FACILITY BY KIT, SUNFIRE, AND CLIMEWORKS.

6.2. SAF and Renewable Diesel Feedstock Suitability

Scaling up SAF and renewable diesel production encounters a major challenge: sourcing an adequate and consistent supply of sustainable feedstocks. This is further complicated by the intricate nature of the market, characterised by diverse feedstock options, geographical fragmentation, ongoing debate regarding social and sustainability issues, and feedstock compatibility with technological pathways.

As SAF and renewable diesel can be derived from a wide range of feedstock sources, it is essential to assess the suitability of each feedstock against various criteria, such as environmental impact, sustainability, domestic supply, availability, and costs. This is shown for the PICTs in **Table 30**.

TABLE 30. FEEDSTOCKS FOR SAF AND RENEWABLE DIESEL PRODUCTION AND ASSESSMENT AGAINST GHG REDUCTION POTENTIAL, SUSTAINABILITY, AND AVAILABILITY IN THE PICTs.¹⁹³

Feedstock Type	Feedstock Category	Feedstock Examples	GHG Reduction	Sustainability *	Availability **
1st gen/crop-based	Edible oil crops	Palm, soybean, sunflower, canola			
	Edible sugars	Sugar cane, maize			
Advanced and waste	Waste and residue lipids	Used cooking oil, tallow, POME			
	Purposely grown energy plants	Jatropha, pongamia, camelina, switchgrass			
	Agricultural residues	Rice straw, bagasse, corn stover			
	Forestry residues	Branches and other un-merchantable leftovers			
	Wood-processing waste	Sawmill slabs, sawdust, wood chips			
	Municipal solid waste	Food and garden waste			
	Reusable plastic waste				
Recycled carbon	Industrial waste gas	CO ₂ from carbon capture			
	CO ₂ from direct air capture	CO ₂ from direct air capture			
Non-biomass based	CO ₂ from direct air capture	CO ₂ from direct air capture			

* The sustainability metric is primarily related to food security and land use change.

** The availability metric is based on the feedstock potential in the PICTs.

High	Medium	Low
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The availability of feedstock is assessed based on the biomass and CO₂ source potential in the PICTs. Concerning biomass availability, forestry waste is abundant in several countries, including Fiji, Vanuatu, PNG, and New Caledonia. Additionally, potential sources of coconut oil, palm oil, vegetable oil, and/or sugarcane feedstock can be found in various regions,

such as Fiji, Samoa, Solomon Islands, Papua New Guinea, New Caledonia, and Kiribati. However, these types of feedstocks may present competing issues with food production, as well as for electricity generation in some locations. In addition to biomass, CO₂ can be obtained from point emissions or through direct air capture and utilised as feedstock. There is potential for capturing CO₂ from bioenergy plants like Nabou Green Energy, Fiji Sugar Corporation (FSC), and Tropic Wood Industries in Fiji. Alternatively, CO₂ from the atmosphere can be extracted via direct air capture (DAC) which can be deployed in any location depending on the land availability.

6.3. SAF and Renewable Diesel Production Cost Analysis

The current price disparity of fossil jet fuel and fossil diesel with SAF and renewable diesel is estimated up to five times higher, as there are a wide range of requirements for scaling SAF and renewable diesel production, encompassing research and development, developing feedstock supply chain, and building new production hubs.

To achieve cost reduction, it is essential to have strong demand signals and implement policy-driven actions. Over time, prices will significantly decrease due to the improvement of technology and economies of scale (**Figure 45**).

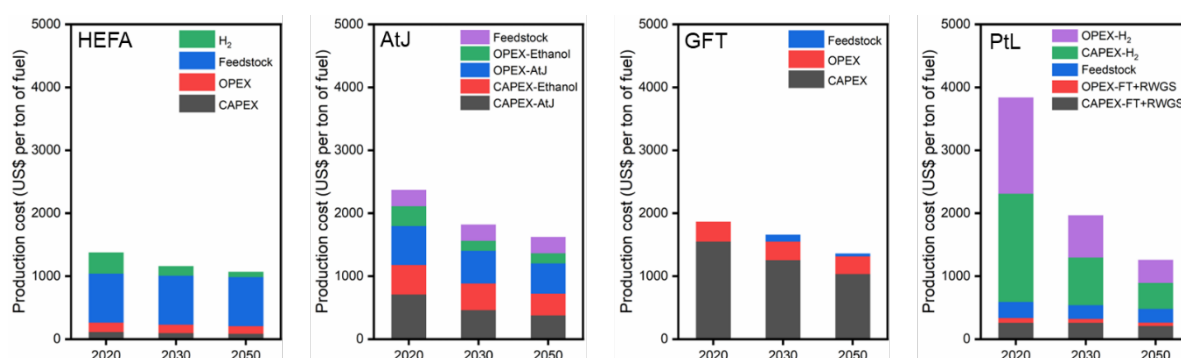


FIGURE 45. COSTS OF SAF AND RENEWABLE DIESEL PRODUCTION VIA HEFA, AtJ, GFT, AND PtL. THESE RESULTS ARE BASED ON LITERATURE PROJECTIONS AND ARE SUBJECT TO CHANGE FOR THE SPECIFIC ANALYSIS OF THE PICTS.¹⁹³

- **HEFA** will likely remain the most cost-competitive option through 2030 as it requires relatively little CAPEX. However, the primary barrier of HEFA is the cost of feedstock, which is not likely to get significantly cheaper. The potential cost reduction for the HEFA process, up to 22% decline, comes mainly from declining H₂ production costs.
- **AtJ** production costs are highly dependent on ethanol costs. While bioethanol from first-generation feedstock is already mature, the production of bioethanol from second-generation crops and waste is currently immature. Further cost reduction can depend on feedstock choices, scale, and learning curve effects.
- **GFT** is a SAF production process with high CAPEX (around 80% of production costs). This process is considered highly flexible with the type of feedstock used including low-cost resources such as municipal solid waste. There is a high potential for cost reduction for the GFT process through economies of scale, CAPEX requirement reduction, and FT process improvement.
- **PtL** is CAPEX-intensive, and the production costs are primarily driven by operating and input costs, including green electricity and sustainable CO₂ price. PtL has

significant cost reduction potential through lower-cost electrolyzers, scale effects, and cheaper renewable electricity, hydrogen, and captured CO₂.¹⁹³

These considerations are summarised in **Table 31**.

TABLE 31. COST DRIVERS AND COST REDUCTION CONSTRAINTS OF SAF AND RENEWABLE DIESEL PRODUCTION VIA HEFA, ATJ, GFT, AND PTL.¹⁹³

	HEFA	AtJ	GFT	PtL
Cost drivers	<ul style="list-style-type: none"> Feedstock price accounts for most of the production cost The cost of green H₂ presents the largest opportunity for cost improvement 	<ul style="list-style-type: none"> Refining ethanol into jet fuel is the biggest cost bucket Ethanol production and jet fuel production are CAPEX-intensive 	<ul style="list-style-type: none"> GFT production cost is largely driven by capital cost. 	<ul style="list-style-type: none"> The cost of electricity is the primary driver PtL is CAPEX-intensive and dependent on sustainable CO₂ price
Cost reduction constraints	<ul style="list-style-type: none"> Limited supply of feedstock 	<ul style="list-style-type: none"> OPEX of the refining step likely remains relatively high 	<ul style="list-style-type: none"> CAPEX of gasifier remains high 	<ul style="list-style-type: none"> Despite a steep decline, renewable electricity costs remain substantial

While large-scale production often benefits from economies of scale, small-scale and decentralised SAF and renewable diesel production could potentially become economically viable, accompanied by various additional advantages. Ensuring that small-scale facilities have access to advanced and efficient technologies, a consistent supply of local waste carbon resources, and a willingness from niche markets or specialised customers (e.g., regional airlines, private aviation, and local transportation services) to purchase SAF and renewable diesel can assist in reducing costs for small-scale production.

Small-scale decentralised production can have a positive impact on local and regional economies by creating jobs and supporting local feedstock suppliers. Furthermore, small-scale operations can be more agile and adaptable, allowing facilities to experiment with different feedstocks and customer segments. This flexibility is crucial for enabling innovation and responsiveness to changing market demands, particularly during the early adoption stage.

6.4. SAF and Renewable Diesel Around the World

In response to growing global net zero commitments, initiatives to deploy SAF and renewable diesel production hubs have increased across the world (**Figure 46**). SAF and renewable diesel are seen as drop-in fuels that can be directly and quickly integrated within the existing energy system by leveraging current storage and distribution networks, and as such, end-users will not need to change their business models.

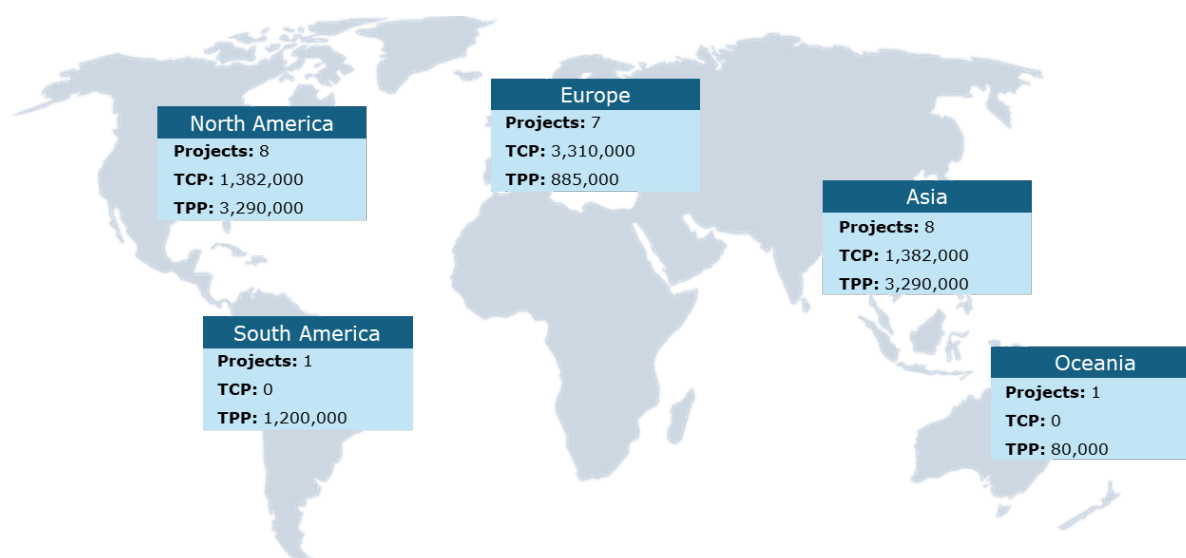


FIGURE 46. CURRENT AND PLANNED SAF AND RENEWABLE DIESEL PRODUCTION ACROSS THE GLOBE.²⁰⁶
 NOTE: TCP; TOTAL CURRENT CAPACITY IN TONNES PER DAY. TPP; TOTAL PLANNED CAPACITY IN TONNES PER DAY.

In the Asia-Pacific region, Neste's refinery in Singapore is the largest synthetic fuels production hub with a capacity of 2.6 million tonnes of synthetic fuels per annum, including 1 million tonnes of SAF and 1.6 million tonnes of renewable diesel.¹⁹⁷ The pathway is the HEFA process, converting oil waste into renewable fuels. Additionally, through its state-owned enterprise, PT Pertamina, Indonesia has produced approximately 0.4 million tonnes of their "bioavtur" branded SAF in the Cilacap refinery. Like Neste, the process used in Pertamina's refinery is HEFA, converting crude palm oil into hydrotreated vegetable oil (HVO) that can be used as SAF.²⁰⁷

In Australia, while the government is yet to roll out SAF and renewable diesel targets, the private sector has taken considerable interest in deploying SAF production and applications, including Qantas, Virgin Australia, Brisbane Airport, BP, Ampol, Oceania Biofuels, and Licella Holdings.

SAF and renewable diesel have been implemented for end-use technologies such as aviation, mining, and logistics. ATR, Swedish airline Braathens Regional Airlines and Neste collaborated to enable the first ever 100% SAF-powered test flight on a commercial regional aircraft.²⁰⁸ The historic test flight took place in Sweden. Rio Tinto has completed the full transition of its heavy machinery from fossil diesel to renewable diesel at its Boron operations located in California.²⁰⁹ The transition arrives after an initial trial of switching fossil diesel to renewable diesel in a US Borax haul truck in partnership with Neste and Rolls-Royce. DHL has partnered with Formula 1 to showcase more sustainable logistics by introducing the inaugural fleet of trucks, running on a renewable diesel.²¹⁰ The new trucks reduce carbon emissions while maintaining the same level of performance in terms of load capacity and travel distance as their fossil diesel counterparts. These end-use demonstrations suggest that SAF and renewable diesel are safe to use in the existing engines, with most applications up to 50% blend ratio. This is also evidenced by feedback from end-use technology providers, such as Airbus, stating that all their aircraft and helicopters are capable of flying with up to a 50% blend of SAF. They also have a goal to enable 100% SAF capability by 2030 for commercial and military aircraft and helicopters.

Opportunities and Challenges for SAF and Renewable Diesel in the PICTs

In the Pacific Island Countries and Territories (PICTs), there are significant opportunities for SAF and renewable diesel to assist in decarbonising the regional economy, especially hard-to-abate sectors. Several potential applications of SAF and renewable diesel applications in the PICTs are described in **Table 32**. For example, SAF and renewable diesel can be potentially used in the aviation and mining sector in the region. Airlines in the region are yet to announce any SAF procurement targets. Fiji Airways' newest Airbus A350-900 XWB aircraft has flown 8,520 km journey from Singapore to Nadi, Fiji powered by a SAF blend.²¹¹ Fiji Airways is about to launch a global fuel supply tender to secure future supply of SAF to meet its sustainability objective. Air Niugini has also purchased four Trent 1000 engines to power its two new Boeing 787-8 Dreamliner aircraft which can technically operate at up to 50% SAF blend. In addition to aviation offtakers, there are also a large number of potential mining offtakers that may seek to procure renewable diesel, including: Societe Minere de Sud Pacifique (New Caledonia), Dome Gold Mines (Fiji, PNG), Vatukoulia Gold Mines (Fiji), Lion One Metals Limited (Fiji), Ok Tedi Copper and Gold Mine (PNG), and Lihir Gold Mine (PNG).

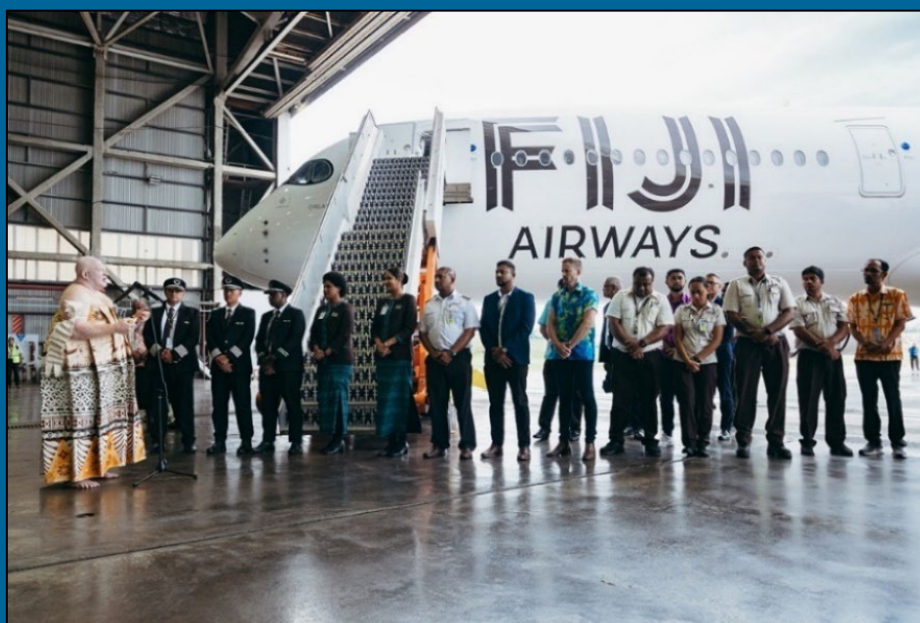


FIGURE 47. FIJI AIRWAY'S NEWEST AIRBUS A350-900 XWB AIRCRAFT FLOWN FROM SINGAPORE TO NADI, FIJI POWERED BY A SAF BLEND.

Despite the potential, several challenges exist for SAF and renewable diesel in the PICTs. The theoretical feedstock availability for SAF and renewable diesel production in the region is relatively limited. There is also the concern of potential land competition when it comes to growing dedicated energy crops. Moreover, the region lacks the necessary infrastructure to support the entire SAF and renewable diesel value chain. One potential solution that PICTs could consider is sourcing SAF and renewable diesel from neighbouring countries like Singapore and Indonesia, which already possess established synthetic fuel production facilities.

Table 32 highlights the applications, benefits, and development required for the main SAF and renewable diesel use cases relevant to the PICTs.

TABLE 32. SAF AND RENEWABLE DIESEL END USE CASES IN THE PICTs: POWER GENERATION AND FUEL APPLICATIONS.

Power Applications	Description	Development required	Benefits
Local generators	Renewable diesel can serve as backup power for local communities and even households during periods of grid instability.	Diesel generator for stationary power applications is a mature technology. Renewable diesel can fully/partially replace conventional diesel used to run diesel generators.	Renewable diesel storage as a liquid in fuel tanks is simple, stable, and easily distributed. Renewable diesel can be safely used in the existing diesel generators without requiring modifications.
Grid backup	Renewable diesel can also be used to generate heat and steam in industrial boilers, which can be combined with gas turbines to generate power on a larger scale such as for grid backup.	New infrastructure and equipment are required.	
Fuel Applications	Description	Development required	Benefits
Aviation	SAF is a prime candidate as an alternative to fossil jet fuel. SAF enables immediate decarbonisation of the aviation sector.	SAF can substitute fossil jet fuel to run aircraft with high safety and compatibility to be implemented within the existing infrastructures and engines.	SAF and renewable diesel can reduce lifecycle carbon emissions by up to 80% compared to traditional jet fuel, and renewable diesel has a 65% lower carbon emission intensity compared to conventional diesel. SAF and renewable diesel can serve as a drop-in fuel with high safety and compatibility with the current infrastructures and engines.
Maritime transportation	Renewable diesel is a prime candidate as an alternative to diesel bunker fuel to fuel maritime vessels.	Renewable diesel can substitute conventional diesel to run maritime vessels with high safety and compatibility to be implemented within the existing infrastructures and engines.	
Road transportation	Renewable diesel is a prime candidate as an alternative to diesel fuel for heavy-duty road transportation such as long-haul trucks.	Renewable diesel can substitute conventional diesel to run heavy-duty road transportation with high safety and compatibility to be implemented within the existing infrastructures and engines.	
Mining operation	Renewable diesel can fuel mining operations particularly to operate the heavy-duty equipment such as excavators and mining trucks.	Renewable diesel can substitute conventional diesel to run mining equipment with high safety and compatibility to be implemented within the existing infrastructures and engines.	
Heating	Renewable diesel can be used to generate heat and steam in industrial boilers.	Renewable diesel has high compatibility with the existing industrial boilers, substituting the conventional diesel.	

7. Conclusion

It is increasingly likely that H₂ and derivatives have a role to play in a decarbonised and renewable-driven energy future of the PICTs. Findings from **Report A** suggested that a complete transition of the PICTs' energy supply to green fuels would require 1 – 2 Mtpa of low-emission H₂ (on an energy basis), a considerable undertaking given at present the global supply of low-emission hydrogen is less than 1 Mtpa (0.7% of the global H₂ supply).

Analysis from this report suggests that while the technology for supplying and using H₂ and derivatives has reached a high level of technical maturity, the present lack of infrastructure and economic/technical resources in the PICTs will limit the offtake of H₂ and derivatives. Therefore, rather than comprising an envelope solution for energy security and decarbonisation of the PICTs, H₂ and derivatives would likely be applicable and have a competitive advantage in niche applications and hard-to-abate sectors. Through the analysis in this report, the market opportunities for green hydrogen and derivatives in the Pacific region is revised from our preliminary analysis in **Report A**.

TABLE 33. REVISED EARLY MARKET OPPORTUNITIES FOR GREEN HYDROGEN TECHNOLOGIES IN THE PACIFIC REGION.

Application	Hydrogen	Methanol	Ammonia	Renewable Diesel	SAF
Seasonal power storage	✓			✓	
Power Generation	✓			✓	
Land mobility fuel	✓	✓		✓	
Maritime fuel		✓	✓	✓	
Aviation fuel					✓
Chemical manufacturing	✓	✓	✓		

In particular, a near-term opportunity lies in the generation of biogenic methanol, SAF, and renewable diesel, as they can be locally generated at competitive costs with incumbent fossil fuels using regional biomass resources (however, the challenges faced by the region in researching biomass-based fuels must be recognised). Moreover, given the large-scale demand for liquid fuels in the region, they can be deployed as a drop-in replacement for fossil fuels, be distributed and utilised through existing infrastructures and networks, making them both technically and socially acceptable. In contrast, e-fuels initially would likely be more competitive in distributed, small-scale applications within remote and off-grid environments. For example, green hydrogen could potentially be used for small-scale energy generation for critical infrastructure or in remote communities and resorts. Widespread distribution of hydrogen across the PICTs would be challenging due to the lack of H₂-ready infrastructure to support the transport and storage of H₂. Therefore, at scale, electrolysis-based H₂ could be used to generate e-fuels (e-methanol, renewable diesel, and SAF) that can then be distributed within and across the PICTs through the existing fossil fuel networks. As a long-term opportunity, there is potential for these regions to emerge as a green shipping corridor as the PICTs can act as supply hubs for maritime

fuels (methanol and ammonia) to support domestic, commercial, and leisure ships passing through the region.

Moreover, it is important to acknowledge the analysis is based on desktop research and technology stakeholder engagement from a global context. The next stage of the analysis involves a region-wide engagement with industry, government, and stakeholders through the planned in-country fact-finding workshops. These findings will then be complemented with **Report C** which will provide further detailed modelling and economic assessment of the potential scenarios for the development of a hydrogen economy in the PICTs. Altogether, these efforts would make the foundation for the Pacific Hydrogen Strategy that will build on the analysis in the subsequent reports and engagements to provide a roadmap for a Pacific hydrogen future.

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