



# **Techno Economic Assessment of Hydrogen Value Chain in the Pacific**

Draft for Consultation | June 2024

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## About the Project

The Efate outcome statement, a significant declaration 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 timebound 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 was complemented by further analysis in [Report B](#), which assessed the status of current and emerging H<sub>2</sub> technologies that can be deployed in the Pacific. It identified key market opportunities based on technology maturity and commercial readiness. This report ([Report C](#)) will focus on mapping the energy resources, land availability, infrastructure, and other feedstocks that would be required to establish the H<sub>2</sub> economy in the PICTs and will investigate the economics of developing the H<sub>2</sub> economy. The overall findings from these reports will then make the basis of a regional hydrogen roadmap. These reports will be complemented by an open-source tool for techno-economic assessment of potential projects in the region (in development), as well as masterclass/knowledge resources to support the PICTs in becoming H<sub>2</sub>-ready. These will be made available through our website (<http://pacific2strategy.com>).





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## List of Abbreviations

<b>AE</b>	Alkaline Electrolyser	<b>NDCs</b>	Nationally Determined Contributions
<b>AEM</b>	Anion Exchange Membrane Electrolyser	<b>MeOH</b>	Methanol
<b>AtJ</b>	Alcohol to Jet Process	<b>OPEX</b>	Operating Costs
<b>bbl</b>	Barrel of oil/diesel equivalent	<b>P2X</b>	Power to X
<b>CAPEX</b>	Capital Costs	<b>KPI</b>	Key Performance Indicators
<b>CEPCI</b>	Chemical Engineering Plant Cost Index	<b>PICTs</b>	Pacific Island Countries and Territories
<b>CO<sub>2</sub></b>	Carbon Dioxide	<b>PEM</b>	Polymer Membrane Electrolyser
<b>CRI</b>	Commercial Readiness Index	<b>PNG</b>	Papua New Guinea
<b>DAC</b>	Direct air capture	<b>PV</b>	Photovoltaic – Solar Panels
<b>EVs</b>	Electric Vehicles	<b>RD</b>	Renewable Diesel
<b>FCEVs</b>	Fuel Cell Electric Vehicles (FCEVs)	<b>RMI</b>	Republic of the Marshall Islands
<b>FSM</b>	Federated States of Micronesia	<b>tpd</b>	Tonnes per day
<b>GDP</b>	Gross Domestic Product	<b>tpa</b>	Tonnes per annum
<b>GFT</b>	Gasification coupled with Fischer Tropsch reactor	<b>SAF</b>	Sustainable Aviation Fuel
<b>GL</b>	Gigalitres (million litres)	<b>SOEC</b>	Solid Oxide Electrolyser Cell
<b>GJ</b>	Gigajoules	<b>STP</b>	Standard temperature and pressure
<b>GW</b>	Gigawatts	<b>TJ</b>	Terajoules
<b>H<sub>2</sub></b>	Hydrogen	<b>TRL</b>	Technology Readiness Level
<b>HEFA</b>	Hydroprocessed Esters and Fatty Acids	<b>TWh</b>	Terawatt hours
<b>Ha</b>	Hectares		
<b>kg</b>	Kilogram		
<b>km<sup>2</sup></b>	Square kilometres		
<b>ktpa</b>	Kilotonnes per annum		
<b>kW</b>	Kilowatt		
<b>L</b>	Litres		
<b>LCA</b>	Life Cycle Assessment		
<b>LHV</b>	Lower heating value		
<b>MCA</b>	Multi-Criteria Assessment		
<b>MeOH</b>	Methanol		
<b>Mpa</b>	Megapascals		
<b>Mtpa</b>	Mega tonnes per annum		
<b>MSW</b>	Municipal Solid Waste		
<b>MW</b>	Megawatt		
<b>MWh</b>	Megawatt hours		
<b>NH<sub>3</sub></b>	Ammonia		

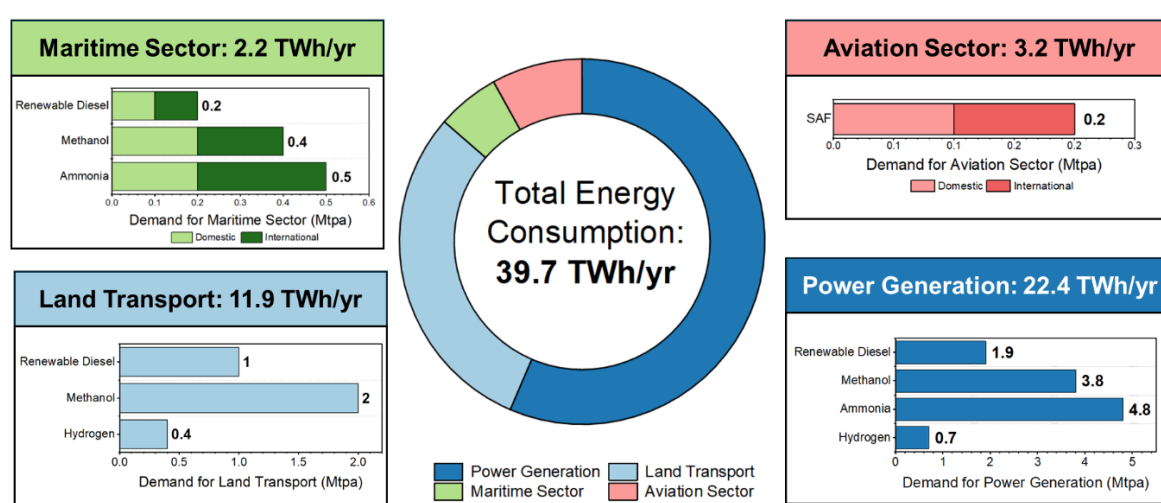
# Executive Summary

## Highlights

- This report builds on the findings of Reports A and B, offering an in-depth investigation into the economic feasibility and regional infrastructure readiness for developing a hydrogen (H<sub>2</sub>) and derivative value chain within the Pacific Island Countries and Territories (PICTs). The analysis is conducted from a techno-economic perspective, focusing on both production and end-use aspects.
- Assessment for potential demand for H<sub>2</sub> and its derivatives in sector specific end use cases reveals that potentially 1.1 million tons per annum (Mtpa) of H<sub>2</sub> to 6.2 Mtpa of methanol required to replace fossil fuel use across the region.
- An economic framework is employed to assess the production costs of H<sub>2</sub> and its derivatives in the PICTs. This includes calculating the levelised cost of production within the context of the PICTs, and benchmarking these costs against those of fossil fuels. The cost of supply – encompassing both production and distribution – are then integrated with end-use opportunities to estimate the marginal cost of switching fuels. This marginal cost serves as a comparative metric, reflecting the costs of deploying a H<sub>2</sub> or derivative solution relative to the existing fossil fuel system.
- The analysis concludes that biofuels (bio-methanol, SAF, and renewable diesel) are currently more economical than e-fuels (H<sub>2</sub> generation through electrolysis and subsequent conversion to ammonia and e-methanol), provided they are developed at scale with a sustainable and low-cost biomass supply. However, challenges related to biomass availability and infrastructure remain significant. Conversely, e-pathways hold greater potential for cost reductions through ongoing R&D, which is driving down technology costs and improving efficiency.
- From an end-use perspective, several economically competitive opportunities are established. These include dispatchable power generation using H<sub>2</sub>, particularly for smaller islands where H<sub>2</sub> can be transported from larger islands, and the use of renewable diesel for both land and maritime transport. While H<sub>2</sub> use for land transport, ammonia, and methanol for maritime applications, and sustainable aviation fuel (SAF) for aviation could become competitive with lower production costs, these options currently face challenges.
- Despite these promising findings, the report acknowledges several challenges and economic uncertainties that must be addressed. More efficient and established alternatives, such as direct electrification, offer competitive options due to their smaller infrastructure requirements and lower costs. As a result, H<sub>2</sub> and its derivatives may be more suitable as complementary solutions, particularly in niche markets where electrification is not viable, such as heavy-duty transport or applications where these e/biofuels can serve as a drop-in replacement for fossil fuels.



**Hydrogen and Derivative Demand Modelling:** In **Report A**, it was estimated that ~40 TWh/yr of energy is consumed in the PICTs in the form of imported fossil fuels, which is both an economic and environmental burden on the region. Herein, the equivalent amount of H<sub>2</sub> and the derivative needed to displace this fossil demand are estimated by accounting for the energy differences between these fuels. For example, for on-demand power production using H<sub>2</sub> fuel cells vs diesel-based power generation, the energy content differences between H<sub>2</sub> and diesel fuel and the efficiency differences of H<sub>2</sub> fuel cells compared to a diesel generator were considered to evaluate the equivalent demand of H<sub>2</sub>. Refer to the accompanying appendix for details.<sup>i</sup> On a similar basis, it is estimated that displacing imported fossil fuel demand for maritime, land, marine, and aviation-based transport could ultimately require up to ~1 Mtpa of H<sub>2</sub>, 5.3 Mtpa of ammonia, 6.2 Mtpa of methanol, 3.1 Mtpa of renewable diesel (3.6 GL/yr), and 0.2 Mtpa of SAF (0.3 GL/yr), as shown in **Figure A**.



**FIGURE A. ESTIMATED H<sub>2</sub> AND DERIVATIVE DEMAND TO DISPLACE CURRENT FOSSIL FUEL IMPORTS OF THE PICTS.**<sup>ii</sup>

**Hydrogen and Derivative Production Cost:** A costing framework was then used to determine the cost of production of H<sub>2</sub> and derivatives in the t of PICof PICTs Ts for both the e-pathway<sup>iii</sup> and bio-pathway<sup>iv</sup>. The cost of production was evaluated as a levelised cost per unit of fuel (US\$/kg), which was estimated based on capital and operating cost assumptions from the literature and stakeholder consultation. Further sensitivity analysis was conducted to illustrate the variation in the levelised costs in the context of the PICTs (such as additional capital required for installation and supply of technology in the region). These estimated costs were then benchmarked against the current retail price of fossil fuel and global estimates for e/biofuels to provide a pathway to parity based on cost reductions and the ongoing impact of R&D. In addition, the cost of importing these e/biofuels from other emerging markets in the Southeast Asian and Pacific Markets was also evaluated for comparison.

<sup>i</sup> These estimates are based on equivalent energy supply basis while accounting for the energy content and efficiency differences between H<sub>2</sub> and derivatives and the incumbent fossil fuel. Refer to **Appendix A** for calculations.

<sup>ii</sup> These estimates are based on equivalent energy supply basis while accounting for the energy content and efficiency differences between H<sub>2</sub> and derivatives and the incumbent fossil fuel. Refer to **Appendix A** for calculations.

<sup>iii</sup> The e-pathways include hydrogen generation through renewable electrolysis and its subsequent conversion to ammonia through Haber Bosch process (N<sub>2</sub> from air) and methanol through hydrogenation with CO<sub>2</sub> (sourced from industrial/power generation point source, direct air capture or biomass gasification). Refer to **Report B** for details.

<sup>iv</sup> The bio-pathway includes methanol, SAF and renewable diesel generation through biomass driven Hydrotreated Esters and Fatty Acids (HEFA), Alcohol to Jet (AtJ) and gasification (GFT) processes. Refer to **Report B** for details.

**Table A** summarises the key findings. **Overall, as estimated at present, considering the nascent H<sub>2</sub> and derivative market in the PICTs, the production cost of H<sub>2</sub> and derivatives is likely to be significantly higher than their fossil fuel variants and global estimates.** This will most likely apply to the first projects, which will be constrained by a high-risk environment and lack of regional expertise/technology, resulting in higher capital and operating costs. However, as highlighted in the table and elaborated in later sections, ongoing R&D-related and scaling-related capital cost reduction and performance improvements along with established supply chains, economies of scale, project design optimisations and targeted support, the production costs of H<sub>2</sub> and derivatives would potentially become competitive. Overall, New Caledonia, Fiji, Vanuatu, and PNG are found to be the most competitive e-fuel producers due to their inherently better solar/wind resources. Meanwhile, PNG and Fiji could emerge as the hubs for bio-fuel production, given the access to large amounts of feedstocks that can be leveraged at lower prices (wood, coconut waste, and bagasse).

**TABLE A. H<sub>2</sub> AND DERIVATIVE PRODUCTION COST OUTLOOK FOR THE PICTs.**

Derivative	Estimated Cost (US\$/kg)	Cost Benchmark (US\$/kg)		
		Fossil Fuel Alternative <sup>v</sup>	e/biofuel Comparison <sup>vi</sup>	Imported e/biofuel <sup>vii</sup>
Hydrogen	5 – 19	1 – 7 <sup>viii</sup>	2 – 12	12 – 14
Ammonia	0.5 – 5.5	0.4	1.0	0.8 – 1.1
e-Methanol	0.7 – 6.3	0.4 – 0.7	0.8 – 2.4	0.9 – 2.4
bio-Methanol	0.9 – 1.4		0.3 – 1.0	
SAF	1.1 – 14	0.7	2.3	1.4 – 2.7
Renewable Diesel		1.1	1.4	1.1
Derivative	Benchmarks for Cost Parity in PICTs Context*			
Hydrogen	<ul style="list-style-type: none"> <li>Reducing the cost of financing (lowering of the cost of capital from a high risk - 10% to low risk - 5% case).</li> <li>Electrolysers scales of &gt;25 MW</li> <li>Electrolyser capital cost reduction to US\$500/kW.</li> <li>Renewable electricity price of ≤US\$25/MWh (for over 70% capacity factors)</li> </ul>			
Ammonia	<ul style="list-style-type: none"> <li>Low cost H<sub>2</sub> supply (US\$2/kg)</li> <li>Development of Haber Bosch (HB) facilities with a capacity of &gt;100 ktpa</li> <li>Optimum design of HB and electrolysis facility to enable high conversion rate and high operating capacity factor</li> </ul>			
e-Methanol	<ul style="list-style-type: none"> <li>H<sub>2</sub> supply cost below US\$2-8/kg for CO<sub>2</sub> supply cost of US\$50/tonne</li> <li>H<sub>2</sub> supply cost below US\$5/kg for CO<sub>2</sub> supply cost of US\$500/tonne</li> <li>Methanol reactor capacity of &gt;100 tpd</li> <li>High conversion rate and capacity factor</li> </ul>			
bio-Methanol	<ul style="list-style-type: none"> <li>Development of production facilities with capacity of &gt;10 tpd</li> <li>Capital and operating cost reduction</li> <li>Low-cost biomass feedstock</li> </ul>			
SAF				
Renewable Diesel				

**\*Note:** The benchmarks for cost parity have been identified based on the techno-economic assessment applied to the regional context, as elaborated in later sections.

**Hydrogen and Derivative End-Use Cost:** Subsequently, the economics of deploying H<sub>2</sub> and derivatives for specific end-use cases: (i) on-demand power generation using H<sub>2</sub> fuel cells and renewable diesel, (ii) land transport through fuel cell vehicles and renewable

<sup>v</sup> These reflect the current retail cost of fossil fuel variants.

<sup>vi</sup> These reflect the estimated costs for bio/e-variants adopted from literature as a comparison.

<sup>vii</sup> These reflect the cost of importing H<sub>2</sub> and derivatives from regional markets in Southeast Asia and Pacific. The production costs for the H<sub>2</sub> and derivatives were adopted from literature references, whereas the cost of shipping was evaluated using the HySupply Shipping Analysis tool, refer to **section 4.3** of the report for more details.

<sup>viii</sup> Adopted from IEA Global Hydrogen Review 2023. <https://www.iea.org/reports/global-hydrogen-review-2023>

diesel-operated engine, (iii) maritime transport using ammonia, methanol and renewable operated engines and (iv) operating aeroplanes using SAF blends.

Herein, to represent the potential of these opportunities, the marginal cost of fuel shift compared to incumbent fossil fuel was estimated. This marginal cost was assessed using the cost of operating a system for incumbent fossil fuel and subtracting it from the cost of operating the system with H<sub>2</sub> or its derivative. For example, for backup power generation, the marginal costs were evaluated by subtracting the estimated levelised cost of generating electricity using a diesel genset (under the current diesel price in the PICTs) from the estimated levelised cost of generating electricity using an H<sub>2</sub> fuel cell (under the estimated price of generating H<sub>2</sub> in the PICTs).

**Table B** summarises the key findings. **Overall, on an economic basis, the most cost-competitive opportunities are replacing current diesel use with renewable diesel for power generation, land transport and maritime applications and deploying an H<sub>2</sub> fuel cell based on demand power generation for extended durations (over 6 hrs of operation) as** they have a marginal cost of 0-1 times higher per unit. Power generation using renewable diesel (supplied at a present estimated cost of US\$1/kg) is at par with fossil diesel-operated systems. In comparison, shifting to fuel cells is also potentially viable as it will cost an estimated US 20 cents/kWh more than an incumbent diesel generator. In contrast, SAF, ammonia, and methanol applications are likely to be less competitive (with a high-end marginal cost of 2 or higher). For example, shifting to ammonia for shipping applications (at the presented estimated supply cost of US\$2/kg) will cost US\$5/t.km compared to the equivalent fossil fuel-operated ship. Therefore, future cost reductions or cost interventions are required to support a viable shift.

**TABLE B. ECONOMIC OUTLOOK OF H<sub>2</sub> AND DERIVATIVE END USE OPPORTUNITIES IN THE PICTs.**

End Use	Marginal Cost of Shift to H <sub>2</sub> and Derivative <sup>ix,x</sup>									
	H <sub>2</sub>		Ammonia		Methanol		Renewable Diesel		SAF	
Power-Gen	0 – 0.6		-		-		0 – 0.25		-	
Land Transport	0.8 – 2.5		-		-		0 – 0.25		-	
Maritime Use	-		0 - 18		0 - 16		0 - 1		-	
Aviation Use	-		-		-		-		0 - 2	
End Use	Fuel cost needed for parity with incumbent fossil fuel (US\$/kg)									
	H <sub>2</sub>		Ammonia		Methanol		Renewable Diesel		SAF	
	Current Price	Price for Parity	Current Price	Price for Parity	Current Price	Price for Parity	Current Price	Price for Parity	Current Price	Price for Parity
Power-Gen	5 - 19	<13	0.5 – 5.5	-	0.7 – 6.3	-	1.1 – 1.4	1	1.1 – 1.4	1
Land Transport		<2		-		-		1		1
Maritime Use		-		-		-		1		1
Aviation Use		-		-		-		1		1

Guide
Not Applicable
Marginal Cost in the range of 0 – 2
Marginal Cost in the range of 0 – 1
Marginal Cost in the range of 0 – 0.5
Marginal Cost in the range of 0 – 0.25

<sup>ix</sup> Marginal cost of US\$0/unit or below reflects parity with incumbent fossil fuel. In contrast, a value higher than US\$0/unit represents a premium that would be incurred for shifting to H<sub>2</sub> and derivative compared to the incumbent fossil fuel (cost for fossil fuel operated system subtracted by the H<sub>2</sub>/derivative system).

<sup>x</sup> These marginal costs are estimated based on an average supply cost (including production and distribution to end user) of US\$10/kg of H<sub>2</sub>, ammonia of US\$2/kg and methanol of US\$1-2.3/kg, SAF/RD cost of US\$1-2/kg.



**Note:** Here, the economics of H<sub>2</sub> and derivatives are exclusively compared against incumbent fossil fuels. While the competition from electrification in sectors such as ondemand power generation and land transport is acknowledged, a detailed analysis is beyond the scope of this study.

Below, the cost conditions needed for the H<sub>2</sub> and derivatives to become competitive in the considered market sectors are elaborated:

- **On-demand/backup power generation:** For a viable shift for H<sub>2</sub>-based on-demand power generation (at least 8 hours of operation a day), the H<sub>2</sub> would have to be supplied below US\$10/kg, whereas a renewable diesel (RD) cost of US\$1/kg would be required.
- **Land transport:** For a viable shift to fuel cell-powered vehicles, H<sub>2</sub> fuel costs (including production and dispensing) of US\$2/kg or below would be needed. RD costs of US\$1/kg would be required.
- **Maritime use:** Similarly, a supply cost of US\$<0.5/kg for ammonia and methanol, whereas RD at a cost <US\$1/kg would be needed for viable maritime use.
- **Aviation use:** For a viable shift for SAF as an aviation fuel, SAF costs below US\$1/kg would be required.

These costs for methanol, SAF, and RD are possible if generated using the biomass pathway, provided they are produced at scale and for low feedstock costs in the near term (prior to 2030). In contrast, shifting to H<sub>2</sub>, ammonia, and methanol generated through the e-pathway is likely to become inherently economic post-2030 and, therefore, in the absence of subsidies/incentives, would incur a premium due to their higher production costs.

**Challenges for H<sub>2</sub> and derivatives adoption in the PICTs:** Although the potential for competitive end-use opportunities for H<sub>2</sub> and its derivatives is recognised, significant infrastructural and economic challenges persist:

- Chief amongst the challenges is the regional capacity, especially the lack of H<sub>2</sub> and derivative-ready skills and expertise, as well as a yet-to-be-established supply chain of technology and services. While the region has experience in developing renewable energy and bioenergy projects, H<sub>2</sub>, methanol, and ammonia are new fuels for the region and, therefore, would require both workforce upskilling and social acceptance and regulation.
- For e-fuel production, a significant limitation is the high capital cost of technology, which is expected to remain elevated in the near term (renewable-driven electrolysis technology is likely to become competitive post-2030 globally). This issue is further compounded by the inherently higher project development costs in the PICTs. In comparison, bio-based pathways may be more cost-effective. Still, their success depends on large-scale deployment and a reliable, low-cost biomass supply at the regional level—both of which require substantial financial support and high upfront investment.
- Moreover, there is competition for critical resources such as water, grid infrastructure, and renewable resources like biomass. Water, a key feedstock for both e-fuel and biofuel pathways, must be supplied at high purity, necessitating new infrastructure like desalination plants or wastewater recycling facilities. While these projects would entail significant upfront costs, they could also enhance regional water security. Additionally, biomass and renewable resources may face competition from direct electrification efforts.

- Compatibility with existing infrastructure, particularly fuel distribution and storage networks, is another crucial factor. Biofuels must integrate seamlessly with current systems to capitalise on their advantage of serving as a drop-in replacement for fossil fuels.

Nevertheless, if these challenges are overcome, H<sub>2</sub> and derivatives, due to their advantage of being versatile compared to electrification, will enable them to develop niche use cases, particularly for transport applications such as maritime and aviation, which would require significant amounts of energy and for which there are barriers to entry for electrification technologies such as footprint limitations. Beyond these niche applications, H<sub>2</sub> and derivatives are likely to play a complementary role. Given that the region has made significant progress in growing the share of renewables and electricity use in their energy mix, the deployment of H<sub>2</sub> and derivatives should not take away focus from this growth.

# 1. The Case for A Pacific H<sub>2</sub> Value Chain

## 1.1. Pacific's Drive for Decarbonisation

In a global context, the Pacific Islands Countries and Territories (PICTs) region is a relatively small contributor to global greenhouse gas emissions, contributing only 0.05% of total energy-related CO<sub>2</sub> emissions. However, a fundamental energy limitation is the present reliance on fossil fuels and a lack of renewable energy penetration.<sup>xi</sup> The energy demand in the PICTs is currently met through a mix of grid electricity generation, transport (land, air, and maritime), and regional industry. Yet, this energy mix is heavily reliant on fossil fuels and has limited penetration of renewable energy sources.

Moreover, almost all these fossil fuels are imported. The financial strain of importing fossil fuels to power critical domestic sectors such as electricity generation and land, maritime, and aviation transport is significant, estimated at around **US\$2.1 billion** (analysis from Report A). Such heavy reliance on imported fossil fuels not only compromises energy security and poses economic risks but also impacts the region's economic growth and hampers the PICTs' ability to meet their climate and sustainable development goals

## 1.2. The Role of Hydrogen and Derivatives

Overall, the PICTs remain committed and have strong ambitions to become net zero by growing their renewable energy generation, given the regional availability of bioresources, solar/wind, hydro and geothermal power potential. This commitment and actions have yielded growth in renewable energy and bio-energy production in the energy mix, with several smaller nations already achieving high levels of clean energy penetration. Yet, from an overall regional perspective, their share of the overall energy use is still limited, with fossil fuel use still accounting for over 50 – 60% of the energy mix.

**Report A** of this series highlights that several of these import-dependent energy sectors, which are challenging to electrify using renewables, hydrogen, and derivatives (including ammonia, methanol, renewable diesel, and sustainable aviation fuel), present a promising solution. These can be generated within the region by leveraging the local renewable/bioenergy resources and distributed across the PICTs to replace imported fossil fuel use. The findings from this assessment were further supported at both COP28 and at multiple regional stakeholder engagements. Highlighting that appropriate and managed H<sub>2</sub> and derivative deployments across the Pacific, implemented through regional solid collaboration between the PICTs, could assist in delivering long-term energy security and the achievement of Nationally Determined Contribution (NDC) targets across the region. This regional collaboration offers a beacon of hope in the face of energy and climate challenges. However, the domestic generation and use of these hydrogen-based fuels require technologies that range in maturity from demonstration and pilot scale to commercially mature, whilst region-specific challenges, operational conditions, and opportunities must also be considered.

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<sup>xi</sup> Renewable energy herein refers to solar, wind, hydro and geothermal energy. Bioenergy is considered as a separate category and comprises ~25% of total energy use. See **Report A** for further details.



Building on these aspects, **Report B** assessed the status of current and emerging green hydrogen and derivatives technologies to highlight their applicability in the global context and replicability in the PICTs. The assessment entailed a thorough technical and economic overview of technologies for the production, distribution (storage and transport), and end use of H<sub>2</sub> and derivatives (ammonia, methanol, renewable diesel—RD, and sustainable aviation fuel—SAF). A multi-criteria assessment (MCA) approach was applied for an inclusive and systematic analysis based on a combination of qualitative and quantitative metrics. These metrics included technology capability (technology maturity and readiness for adoption in PICTs), economic outlook (possible economic competitiveness against incumbent fossil fuel technologies), benefits to the PICTs (emission reduction potential and enhanced energy security), and associated risks (potential safety/social consideration and burden on regional natural resources).

**H<sub>2</sub> and Derivatives Production Technologies: Table 1** Summarises the MCA for the production pathways of green hydrogen and its derivatives, explicitly highlighting renewable production methods, including both biogenic and e-pathways for producing methanol, renewable diesel, and SAF. The MCA indicates that while hydrogen and derivatives production technologies are generally mature, their implementation, particularly in the PICTs, faces short- to medium-term challenges due to high capital costs, water constraints, operational inflexibility, and lack of infrastructure.

**TABLE 1. PERFORMANCE MATRIX FOR HYDROGEN AND DERIVATIVES PRODUCTION TECHNOLOGIES.**

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 Performance
Average	Average Performance
Low	Low Performance

**Note:** These MCA results are based on a global perspective, as assessed in **Report B**. Here, B and E represent biogenic pathways and electrolytic production pathways, respectively.

Overall, the above assessment reveals a significant potential for the region's renewable fuels derived from waste biomass, such as bio-methanol, bio-SAF, and biodiesel (renewable diesel). These can potentially be produced locally using domestic/agricultural wastes, coconut waste/used oils, or municipal solid waste (MSW) and are mostly compatible with existing infrastructures, offering opportunities for reducing fossil fuel imports. Locally generated bio-SAF and biodiesel can be distributed using existing infrastructure as they are direct synthetic replacements with the same physical and

chemical properties. However, on a production basis, these systems are relatively inflexible, preferring steady-state operations and specific feedstocks. Moreover, they are scalable with better economies of scale exhibited at higher quantities, yet the availability of suitable biomass again constrains the overall capacity for production.

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 sustainable biomass resources. These can then be leveraged as carbon feedstocks for generating SAF, methanol, or renewable diesel. Decentralised production would be especially beneficial for hydrogen and ammonia, as it reduces the need for extensive distribution networks currently lacking in the PICTs.

Overall, H<sub>2</sub> commercial electrolyzers, particularly alkaline and PEM systems, have reached a high TRL level (TRL of 9) and are designed to be modular (modules with specified MW capacity) that can be combined in series to increase H<sub>2</sub> production capacity. At present, generally, maximum electrolyser scales with modular sizes of 10 – 20 MW capacities are commercially available, with average project sizes with a cumulative capacity of 100 – 500 MW (<1 GW) being developed and operated.<sup>1</sup> Capacities higher than one GW have been committed and are likely by 2030, but for this, challenges such as finding suitable off-takers along with financial challenges (high cost of development) and technical difficulties (integration of the electrolyser with an appropriate power source and water supply) would have to be managed. Yet, scalability, both in terms of production volume and modular sizes, is essential for economies of scale. As the global capacity for electrolyzers is scaling up and modernised, the learning impacts, economies of scale and supply chain optimisation are all together driving down the per-unit production. Similarly, on a modular basis, an increase in both performance and production efficiency, R&D improvements leading to better design and lesser material consumption, and better overall economics of installation (larger capacity units are easier to install and maintain compared to several smaller capacity units) are leading to cost reduction. Altogether, based on these factors, the unit cost of electrolyzers (\$/kW) is estimated to decrease by a factor of 1.5 times by increasing modular capacities from 1 MW to over 20 MW.<sup>2</sup>

In comparison, Haber Bosch units for ammonia production have historically been developed at high capacities and scales (in the range of 1,000 tpd or higher), which is primarily due to the fact they were deployed as centralised facilities to produce ammonia for large-scale applications such as fertiliser production. Established manufacturers of HB units, such as Linde<sup>3</sup>, KBR<sup>3</sup> and Topsoe<sup>4</sup>, are offering units with production capacities of over 1,000 tpd. Nevertheless, companies such as ThyssenKrupp<sup>5</sup> and Proton Ventures<sup>6</sup> have developed smaller-scale HB units that can produce up to 100 – 500 tpd of ammonia. In comparison, FuelPositive<sup>7</sup> has developed a modular solution that can produce 0.3 tpd of ammonia, but these are still in the development stages and have yet to be commercialised at scale. Nevertheless, from the PICT's perspective, given that ammonia will be used for maritime use, these facilities will likely be built at a scale close to major ports to service freight ships and larger vessels.

Liquid-to-fuel technologies such as HEFA (Hydrotreated Esters and Fatty Acid conversion), gasification, and Fischer Tropsch processes for generating methanol, SAF, and renewable diesel have all reached a high level of maturity. They are also scalable technologically and exhibit cost reduction with increasing capacities under economies of scale. However, their applicability is constrained by biomass supply and type.

**H<sub>2</sub> and Derivatives End Use Technologies:** Similarly, **Table 2** summarises the MCA for the potential end-use pathways of green hydrogen and its derivatives in the PICTs. The opportunities considered include using derivatives for seasonal renewable energy storage for subsequent on-demand power generation and as mobility fuels for land, maritime and aviation-based applications. The enabling end-use technologies have mainly achieved an acceptable maturity level (TRL 6 or higher).

**TABLE 2. PERFORMANCE MATRIX FOR HYDROGEN AND DERIVATIVES END-USE APPLICATIONS.**

Metric	Hydrogen		Ammonia			Methanol B E			SAF B E	Renewable Diesel B E	
	Renewable Energy 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 Performance
Average	Average Performance
High	Low Performance

**Note:** These MCA results are based on a global perspective, as assessed in **Report B**. Here, B and E represent biogenic pathways and electrolytic production pathways, respectively.

**On-Demand Distributed Power Generation:** From a power generation perspective, excess renewable energy resources can be converted to H<sub>2</sub> or renewable diesel and subsequently stored in bulk amounts for seasonal power storage at centralised facilities on major islands that have the available resources and supporting infrastructure. These fuels can then be distributed across the region and transported mainly to smaller islands, remote off-grid sites including island resorts or for backup power for critical infrastructure such as hospitals or telecommunication), where they can be reconverted to electricity using fuel cells or generators for on-demand power.

**Mobility Application:** From a mobility context, H<sub>2</sub> fuel cell-powered vehicle (FCEV) fleets, particularly for public buses or heavy haul trucks, can be adopted in the PICTs. However, the potential of H<sub>2</sub> offtake for the transport sector would be limited due to challenges in developing a refuelling network and the growing competition from battery electric vehicles. In comparison, methanol and renewable diesel blending into existing vehicles are likely to be more promising and can be used as drop-in replacements. Similarly, SAF can be produced and used to service local or international aviation operating in the region. Yet for these fuels to be potentially economically and technically viable opportunities, providing a sustainable supply of biomass can be established along them to be generated



at scale and for globally competitive costs (within an acceptable premium to incumbent fossil fuels), and existing infrastructure can be leveraged to deploy these as drop-in replacements for imported fossil fuels. Their production involves more energy conversions and costs and does require sourcing zero-emission carbon (likely from biomass or potentially direct air capture). Niche opportunities for using ammonia and methanol as maritime fuel are also being developed. However, given the early-stage development and adoption of ammonia/methanol-ready engines, these are likely to be medium- to long-term applications. Therefore, renewable diesel might be more suitable as it can be used in existing diesel-operated engines employed in small ferries and fishing boats.

This assessment further highlights that these technologies are not likely to be an envelope solution for decarbonising the PICT energy network and may initially be limited to more niche opportunities (**Table 3**). Over time, the role and scope of H<sub>2</sub> and derivatives might be expanded, depending on the future energy outlook, policy shifts, changed market and social acceptability, infrastructural improvements, regional skill development, project development experience, and improving economics. The following sections of the report detail the techno-economic assessment (TEA) for green H<sub>2</sub> and derivative production and their subsequent end-use opportunities for a range of market opportunities.

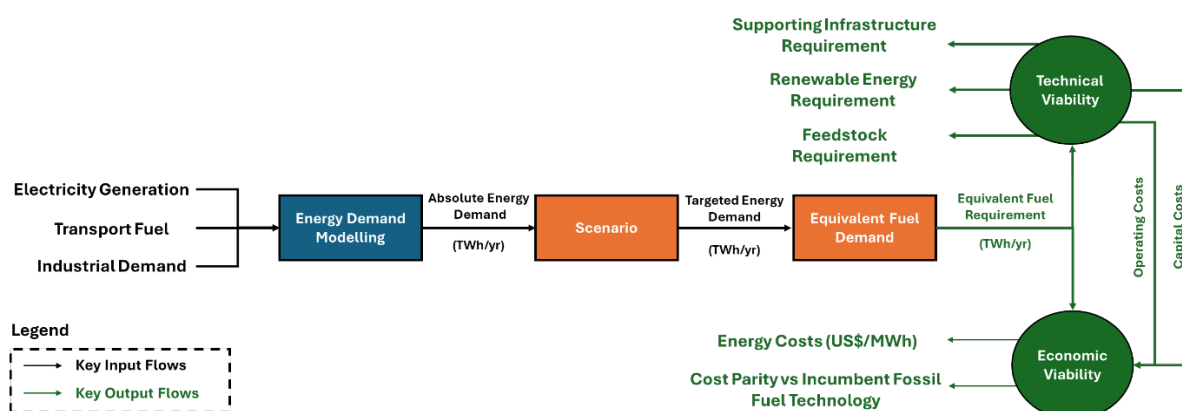
**TABLE 3. REVISED EARLY MARKET OPPORTUNITIES FOR HYDROGEN TECHNOLOGIES IN THE PACIFIC REGION.**

Application	Hydrogen	Methanol	Ammonia	Renewable Diesel	SAF
Seasonal Power Storage	✓			✓	
On-Demand Distributed Power Generation	✓			✓	
Land Mobility Fuel	✓	✓		✓	
Maritime Fuel		✓	✓	✓	
Aviation Fuel					✓

## 2. Assessment Framework

### 2.1. Framework Overview

A purpose-built framework (**Figure 1**) was developed and used to conduct the techno-economic assessment in this report. The first stage of the framework is the determination of the regional energy demand for electricity production, transport, and industrial sectors. This energy demand (referred to as absolute energy demand) is determined in this stage and is then filtered through the scenario screening to establish a target energy demand. This target demand is then used as a base to conduct a reverse mass and energy balance to develop the equivalent demand for green fuels (i.e., green H<sub>2</sub> or its derivative) through the identified technological pathways (**Report B**). In the next stage, an economic assessment is conducted that estimates the cost of production and end-use and compares the cost competitiveness with incumbent fossil fuels. Similarly, a technical viability overview estimates and provides an overview of the scale of supporting infrastructure, renewable energy, and feedstock requirements required to establish the H<sub>2</sub> and derivative value chain.



**FIGURE 1.** TEA FRAMEWORK USED TO ASSESS THE TECHNICAL AND ECONOMIC VIABILITY OF IDENTIFIED H<sub>2</sub> AND DERIVATIVE OPPORTUNITIES IN THE PACIFIC.

These models are elaborated below:

#### Technical Viability

This stage involves determining if the required infrastructure, feedstock, and renewable energy to support the equivalent production of the e-fuels (H<sub>2</sub>, ammonia and e-methanol) and biofuels (bio-methanol, SAF and renewable diesel) are available in the Pacific. For example, an essential requirement is to ensure that the regional renewable energy availability for green fuel production is adequate and temporally correlated with the end-user demand for the fuel. Similarly, there must also be sufficient availability of natural resources, infrastructure, and feedstocks to support the production and distribution of green fuels, including considering limits on water as well as land availability to develop associated solar/wind farms and the profile of renewable energy generation for assessing the renewable energy requirement. Infrastructural requirements involve evaluating the availability of an electricity distribution network, social and policy support, and existing means to support the distribution of green fuels or the practicality of developing these means.

**Note:** These aspects have been assessed as part of the MCA in **Report B**. However, the MCA is conducted from a generic overview of the PICTs. The TEA framework extends beyond this analysis to provide a region- and application-specific overview of the availability of infrastructure and feedstock. Feedstock availability is considered a critical limiting factor, as the adequate availability of renewable energy, water, and biomass will dictate the scale of production. Similarly, currently available infrastructure to support the development of the projects will be an economic advantage.

## Economic Viability

Subsequently, the economic model uses cost scale models to determine potential capital and operating cost requirements (based on the feedstock, equipment, and infrastructural requirements established during the technical viability) to estimate the unit cost of production (US\$/kg). Subsequently, the marginal cost of shifting to H<sub>2</sub> and derivatives relative to the incumbent fossil fuel solutions for specific end-use cases was estimated. To determine the marginal cost of moving to alternative fuels, the difference between the unit cost while using fossil fuels and that of alternative fuels is established. This difference, depending on whether it is positive or negative, then provides the premium (additional costs for fuel shifting) or incentive (the cost savings from fuel savings) incurred by shifting to the H<sub>2</sub> and derivative opportunity.

## 2.2. Assessment Scope

Given the expectation that green H<sub>2</sub> and derivatives are not likely to be a blanket solution, a scenario-based assessment is conducted. Firstly, the demand for these green fuels is assessed based on potential fossil fuel displacement targets (i.e., 10%, 50%, and 100%) for electricity production, transport fuels (land, maritime, and aviation), and industry. Secondly, decentralised applications are assessed where green fuels can be used to supply energy needs for specific use cases, such as fuel cell-based backup power generation for resorts or hospitals; these opportunities are characterised below.

## 2.3. Assessment Scenarios

Considering the screening studies in **Report A** and **Report B**, the following opportunities were identified:

### Electricity Production

Based on our assessment in **Report A**, fossil fuels provide ~22.4 TWh per year of energy towards grid electricity generation in the PICTs. Growth in renewables is likely the predominant strategy for displacing this fossil fuel demand as per the regional NDCs and renewable energy targets, which target 100% renewable electricity supply in the coming decades for many PICTs. As such, green H<sub>2</sub> and derivatives are likely to play a complementary role in this sector. **Report B** highlighted the potential role of fuel cells as a means for on-demand power generation in remote locations and critical infrastructure. As highlighted (in **Report A**), projects such as the Pacific Green Hydrogen Project<sup>8</sup>, initiatives by the New Caledonia mining industries<sup>9</sup> and HDF Energy Australia's project in Fiji are exploring and developing fuel cell use for on-demand power generation<sup>10</sup>.

H<sub>2</sub> and ammonia-ready gas turbines can be deployed to replace existing grid fossil fuel generators for utility-scale power generation. Alternatively, renewable diesel and methanol

can be used as a green drop-in replacement fuel for diesel generators. The Fiji Department of Energy has already conducted demonstration projects for rural electrification of coconut oil-based fuels.<sup>11</sup> Similarly, a study supported by the World Bank conducted biodiesel generation from coconut oil for blending in diesel power generators, which can be technically and economically viable in the PICTs.<sup>12</sup>

In a 100% renewable electrified future, buffer storage would be required to mitigate renewable electricity variability, certainly with wind and solar, as well as potentially hydro and biomass. As such, H<sub>2</sub>, methanol, and renewable diesel might be used as seasonal energy storage for long-term energy storage as an alternative to battery energy storage systems (BESS) and as vectors for energy distribution. Fuel cell technology can be deployed for reliable on-demand power generation/backup power supply for critical infrastructure such as telecommunication towers and hospitals. In addition, they can be deployed as decentralised power generation facilities in off-grid locations and resorts. A study from the German institute, Reiner-Lemoine-Institut GmbH, with the support of the German-New Zealand Chamber of Commerce, conducted a feasibility study for a renewable integrated fuel cell-based power system for tourist areas on the Pacific islands of Samoa, Tonga, Fiji and the Cook Islands.<sup>13</sup> Alternatively, for utility power generation, hydrogen/ammonia-ready turbines can be deployed (which would require a significant overhaul of the current power system due to the lack of gas-based energy infrastructure) or through green fuel blending used in existing diesel generators.

This report will assess the technical and economic viability of these options against diesel-based power generation.

## Transport Sector

The transport sector (including land, maritime, and aviation) comprises around 14 TWh per year of the region's fossil fuel imports (**Report A**).

**Land Transport:** Land transport accounts for 33% of the PICT's fossil fuel energy use (i.e., ~12 TWh per year) and 84% of the energy use by the transport sector. Considering their technology maturity, superior round-trip energy efficiency, and commercial availability, battery electric vehicles (BEVs) are the far more likely option for decarbonising land transport. However, for the heavy-duty sector and long-haul transport (as highlighted in **Report B**), hydrogen and ammonia fuel cell vehicles (FCEVs) are being considered as an alternative to BEV options. Nevertheless, these vehicles still must be proven to be more cost-effective and technically suitable alternatives to BEVs. Provided they can be adopted in the PICTs, FCEVs could potentially be deployed in the region for applications such as inland freight, public transport (buses), and specialised vehicles, including forklifts and garbage collection vehicles.

Alternatively, renewable diesel or bio-methanol blends with diesel fuels can be used as drop-in replacements for fossil fuels. While, to the best of our knowledge, renewable diesel and methanol blending has not yet been attempted in the PICTs region, coconut oil blending has been demonstrated, albeit with changes required for the engine.<sup>14</sup> In comparison, renewable diesel and methanol blending up to 30% are technically usable without the need for specialised engines, as they can be used in their existing diesel engines. As such, these drop-in fuels can potentially provide a stopgap solution to the use of fossil fuels in the transition to emissions-free land transport.

This report will assess the technical and economic viability of hydrogen fuel cells and renewable diesel blending in existing vehicles.

**Maritime Transport:** The domestic maritime sector across the PICTs accounts for ~3% of the PICT's fossil fuel energy use (i.e. ~1 TWh per year) and 7% of the energy use by the transport sector. Analysis in [Report B](#) shows that a shift to methanol, ammonia, and renewable diesel is a possible decarbonisation solution, especially for heavy-duty and longer-distance maritime applications, due to the present lack of an electric alternative. These fuels can also be used for the local needs of fishing and ferry vessels. Recently, the regional stakeholders and maritime heads have gathered and developed the Pacific Regional One Maritime Framework, which aims to adopt decarbonised fuels for maritime applications across the region.<sup>15</sup>

Additionally, as highlighted in [Report A](#), the major ports in the region, such as Port Noumea in New Caledonia, Santo and Port Villa in Vanuatu, Suva in Fiji and Port Funafuti in Tuvalu, play a crucial role in the potential Pacific Green Shipping Corridor. These ports, as part of the regional primary shipping corridors, might act as refuelling stops to supply green fuels for freight and cruises passing through these regions. Their contribution is vital in connecting the USA with Asian, Australasian, and Pacific markets. Marine fuel bunkering can also provide a source of green fuels for shipping operating in the region. This demand for international bunkering fuels would add another 1.2 TWh/yr of energy demand that could potentially be fulfilled with locally produced ammonia, methanol, or renewable diesel.

**Aviation Sector:** The domestic aviation sector accounts for ~4% of the PICTs' fossil fuel energy use (i.e. ~1.3 TWh per year) and 9% of the energy use by the transport sector. The international aviation sector (not considered within the PICTs' domestic energy use) might currently use up to 13 TWh per year (Report A). However, there are challenges in associating this use with the PICTs, as aviation refuelling can occur in multiple airports when travelling international routes. The production of SAF can address the fossil fuels used by regional planes and national airlines operating in the region, potentially replacing up to 9 million bbl of diesel equivalent aviation fuel. Aviation fuel bunkering could also provide a source of SAF for other airlines operating in the region. Fiji has already taken a region-leading role by adopting the new International Civil Aviation Organization Global Framework for Sustainable Aviation Fuel.<sup>16</sup> Moreover, Fiji Airlines has set a remarkable example by successfully flying its Airbus aircraft from Singapore to Fiji using SAF in 2023.<sup>17</sup>

### Regionally Integrated Market

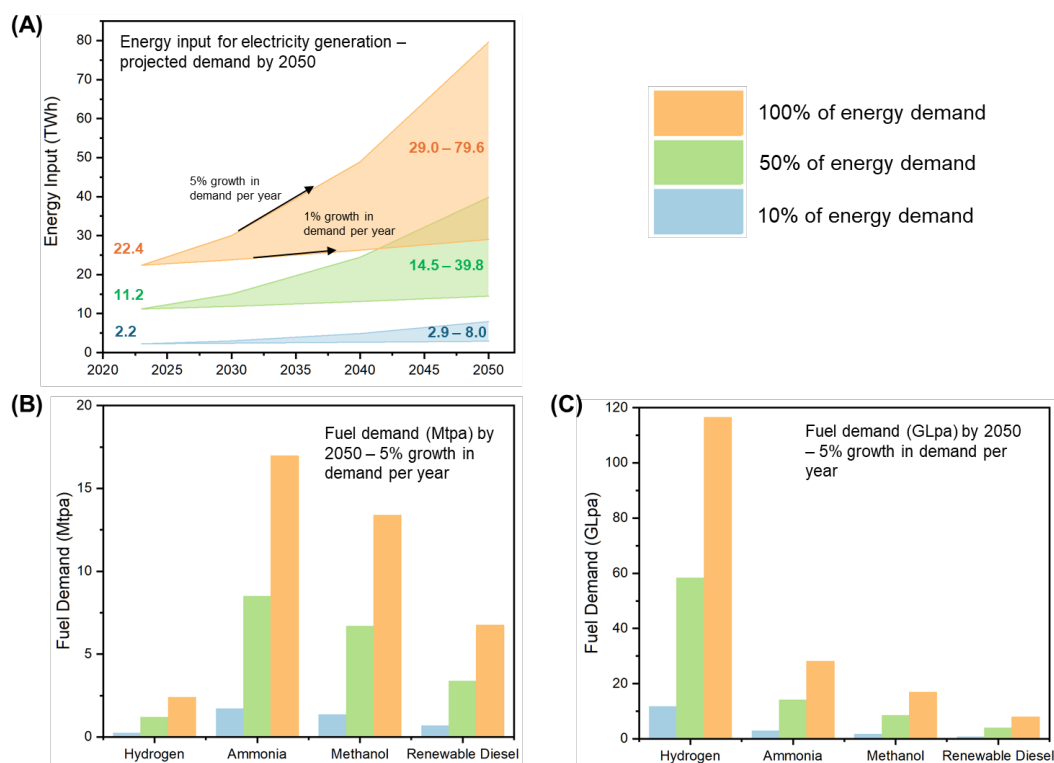
A regional H<sub>2</sub> trade market could be developed. As discussed in [Report A](#), Fiji, Samoa, Vanuatu, the Solomon Islands, PNG, and New Caledonia could potentially become net exporters of H<sub>2</sub> and derivatives for the Pacific region. Moreover, the regional biomass can be used to generate renewable diesel, methanol, and SAF, which might even be exported to the Australasian and Asian markets. Similarly, these markets can also collaborate in the development of a regional market that can support the PICT's energy needs. This report will also assess the technical and economic viability of importing green derivatives from regional markets such as Australia, Indonesia, and Malaysia as a potential alternative to the import of equivalent fossil fuels or the local generation of green fuels.

# 3. Demand Modelling for H<sub>2</sub> & Derivatives

This section elaborates further on the demand modelling scenarios assessed in this study. **Note:** **Appendix A** provides details on the assumptions used and associated calculations.

## 3.1. Electricity Production

Our prior analysis (**Report A**) determined that the total fossil fuel demand for electricity generation in the PICTs is presently around 22.4 TWh/yr. Considering scenarios where electricity demand grows at 1 – 5% per year across the region (**Figure 2A**), this demand may reach 29 – 80 TWh of fossil fuels by 2050, which could be partially or, perhaps even wholly, satisfied through the use of renewable fuels, including hydrogen, ammonia, methanol, and renewable diesel. This involves displacing fossil fuels imports with these renewable fuels that can be employed for utility-scale power generation using large capacity centralised facilities or in off-grid and remote locations where local renewables are challenging to deploy through distributed fuel cells, as well as for long-term seasonal storage of renewable energy in lieu of battery storage. For example, the stretch scenario of completely replacing fossil fuels for electricity generation with hydrogen would require 2.5 Mtpa of H<sub>2</sub> (**Figure 2B**), whereas replacing it with renewable diesel could require up to 8.0 GLpa of renewable diesel (**Figure 2C**).

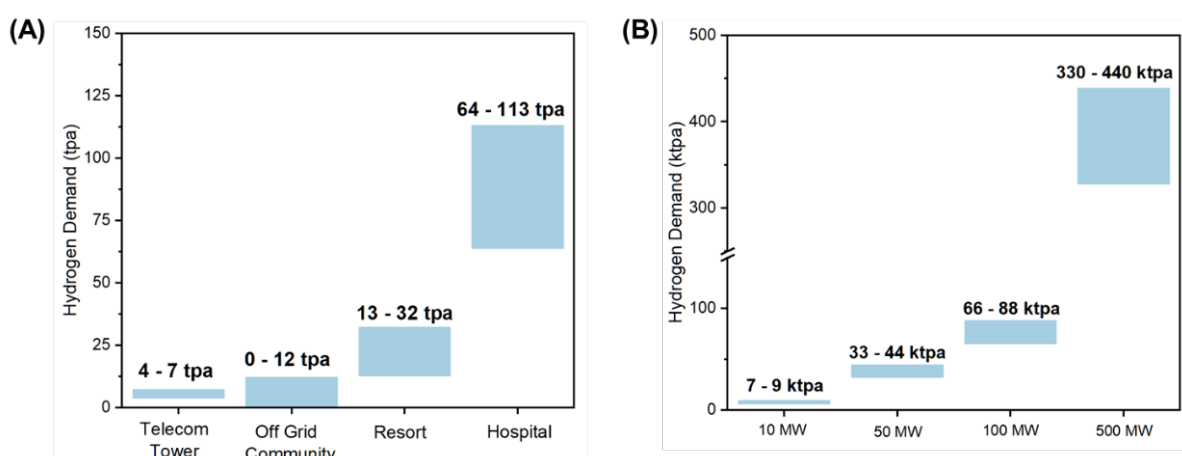


**FIGURE 2. EQUIVALENT DEMAND FOR RENEWABLE FUELS TO FULFILL ELECTRICITY GENERATION REQUIREMENTS OF THE PICTS. HERE (A) REPRESENTS THE GROWTH IN FUTURE ELECTRICITY DEMAND ASSUMING A 1-5% GROWTH PER YEAR SCENARIO. WHEREAS (B) AND (C) REPRESENT THE EQUIVALENT DEMAND FOR SYNTHETIC FUELS TO REPLACE INCUMBENT FOSSIL FUELS ON A MASS (MTPA) & VOLUME (GLPA) BASIS, RESPECTIVELY, BY 2050 (ASSUMING A 5% INCREASE IN DEMAND PER YEAR). NOTE: IN**



THESE FIGURES, THE ENERGY INPUT IN TWH IS ESTIMATED BY ACCOUNTING FOR THE TOTAL FOSSIL FUEL USE IN THE SECTOR ACROSS THE PICTS AS PER OUR ANALYSIS IN **REPORT A**. THIS BASELINE DEMAND IS THEN REPRESENTED UNDER DIFFERENT SCENARIOS TO REFLECT FUTURE PROJECTIONS ASSUMING A 1-5% INCREASE IN DEMAND PER YEAR. MOREOVER, THE BASELINE DEMAND IS THEN CONVERTED TO THE EQUIVALENT REQUIREMENT OF SYNTHETIC FUELS (H<sub>2</sub> & DERIVATIVES) NEEDED TO SUPPLY THE SAME AMOUNT OF ENERGY BY ACCOUNTING FOR THE ENERGY CONTENT OF THE SYNTHETIC FUELS AND THE ENERGY CONVERSION EFFICIENCY OF THE CONVERSION TECHNOLOGY. REFER TO **APPENDIX A** FOR THE DETAILED CALCULATIONS.

**H<sub>2</sub> Use for Power Generation:** In **Report B**, hydrogen fuel cells were proposed as a possible option for distributed power generation in off-grid locations and as backup power solutions for critical applications. Additionally, as green hydrogen availability increases over time, H<sub>2</sub>-ready turbines could be introduced to replace utility-scale diesel generators in off-grid and remote locations. However, we note that hydrogen is unlikely to be a primary source of electricity generation. Locally available wind, solar, hydro, biomass and geothermal generation options would likely be a first option if available, with hydrogen-fuelled generation playing a complementary and critical firming role given the variability of many renewable sources and only relatively short-term energy storage of BESS.

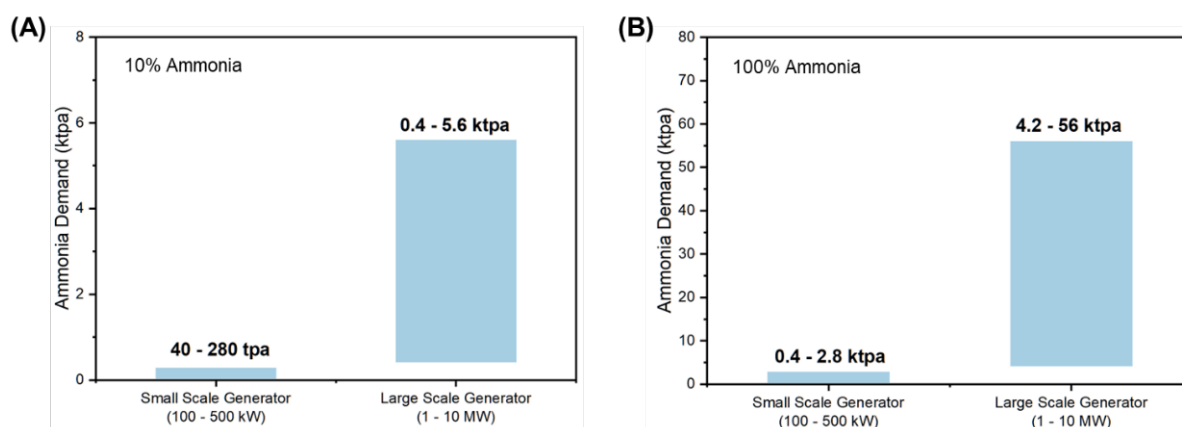


**FIGURE 3. ESTIMATED H<sub>2</sub> REQUIREMENT FOR ON-DEMAND ELECTRICITY GENERATION APPLICATIONS.** HERE, THE ESTIMATED H<sub>2</sub> DEMAND TO (A) GENERATE SPECIFIC END-USE ELECTRICITY DEMAND USING H<sub>2</sub> FUEL CELLS & (B) FOR UTILITY SCALE POWER GENERATION CAPACITY USING H<sub>2</sub> TURBINE ARE PRESENTED. **NOTE:** IN THESE FIGURES, THE BASELINE ENERGY DEMAND OF SPECIFIC END-USE SECTORS IS ESTIMATED – TWH/YR BASIS, WHICH IS SUBSEQUENTLY CONVERTED TO THE EQUIVALENT REQUIREMENT OF SYNTHETIC FUELS (H<sub>2</sub> & DERIVATIVES) NEEDED TO SUPPLY THE SAME AMOUNT OF ENERGY BY ACCOUNTING FOR THE ENERGY CONTENT OF THE SYNTHETIC FUEL AND THE ENERGY CONVERSION EFFICIENCY OF THE CONVERSION TECHNOLOGY. REFER TO **APPENDIX A** FOR THE DETAILED CALCULATIONS.

**Figure 3A** provides an estimated outlook of H<sub>2</sub> demand to supply decentralised power sectors using fuel cells. Of these application areas, supplying electricity for small off-grid communities could require up to 12 tpa of H<sub>2</sub>, while up to 133 tpa could be needed to provide on-demand power for hospitals. Alternatively, utility-scale diesel generators can be replaced with H<sub>2</sub>-fueled turbines, requiring between 66 and 440 ktpa for 100 to 500 MW systems (assuming operation at 10% to 100% H<sub>2</sub> fuel, respectively). However, this opportunity might not be practically realised in the PICTs due to infrastructural development challenges, especially given the region's lack of gas-ready infrastructure and experience.

**Ammonia Use for Power Generation:** Similarly, ammonia has been identified as an alternative to gas-fired engines. Leading turbine manufacturers, including GE and Mitsubishi, are actively developing ammonia-powered turbines. Our estimates (**Figure 4**)

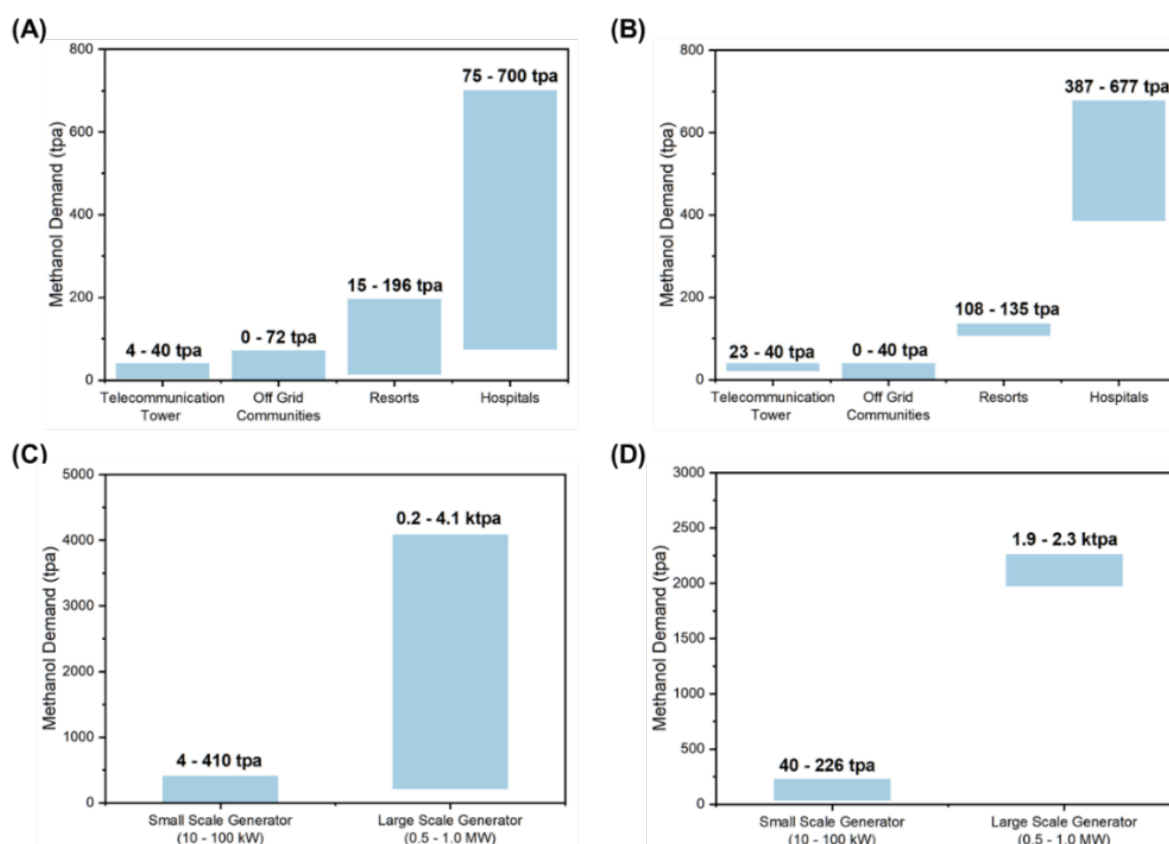
suggest that a large-scale ammonia turbine (around 10 MW) could require 5.6 – 56 ktpa of ammonia, assuming a 10% blend to 100% ammonia.



**FIGURE 4. ESTIMATED AMMONIA REQUIREMENT FOR ON-DEMAND ELECTRICITY GENERATION APPLICATIONS. THE DEMAND IS ESTIMATED FOR (A) SPECIFIC END-USE APPLICATIONS AND (B) UTILITY-SCALE POWER GENERATION CAPACITY.**

Yet, we expect a limited role for ammonia turbines in PICTs, given that deployment of ammonia production and use brings significant safety and other infrastructure challenges, given the inherent toxicity of ammonia and the need for liquefaction plants, special pipelines and tanks, as well as generators.

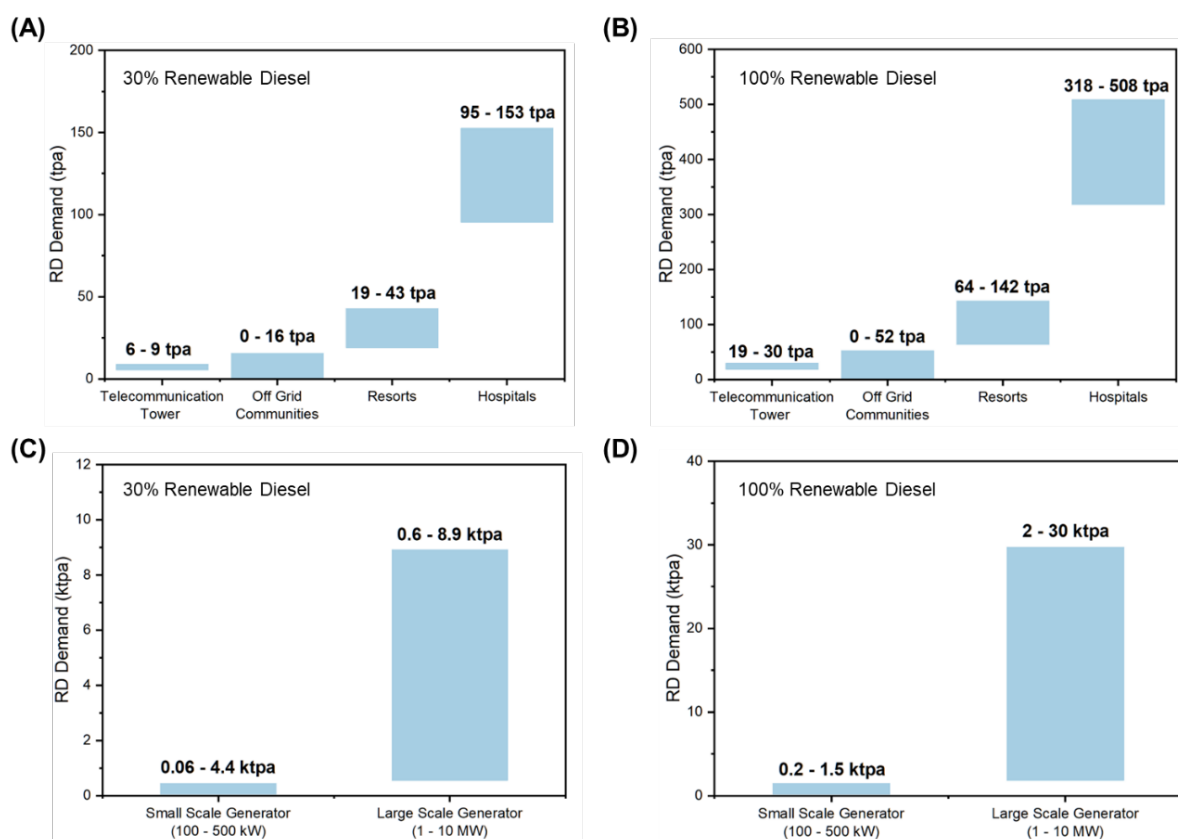
**Methanol Use for Power Generation:** Similarly, methanol can also be employed for electricity generation; **Figure 5** provides the estimated methanol demand for the power supply of various applications.



**FIGURE 5. ESTIMATED METHANOL REQUIREMENT FOR ON-DEMAND ELECTRICITY GENERATION APPLICATIONS. THE DEMAND FOR METHANOL IS ESTIMATED FOR (A) SPECIFIC END-USE APPLICATIONS AND (B) UTILITY-SCALE POWER GENERATION CAPACITY.**

Methanol can then be potentially adopted as a blend with fossil fuels or through specialised fuel cells.<sup>18,19</sup> However, both opportunities will require changes due to infrastructure and end-use applications, as well as differences in fuel properties, especially energy content and combustion profiles, especially for high blends, as highlighted in **Report B**.

**Renewable Diesel Use for Power Generation:** Of all the other options, renewable diesel can offer an easily implementable and scalable alternative. Instead of needing to deploy fuel cells and H<sub>2</sub>/ammonia-ready turbines, renewable diesel can be directly used as a drop-in replacement for fossil fuels (as a blend with conventional diesel or as a direct replacement) in existing diesel-powered generators and power plants. **Figure 6** provides the estimated renewable demand for power supply of various applications under different blends.

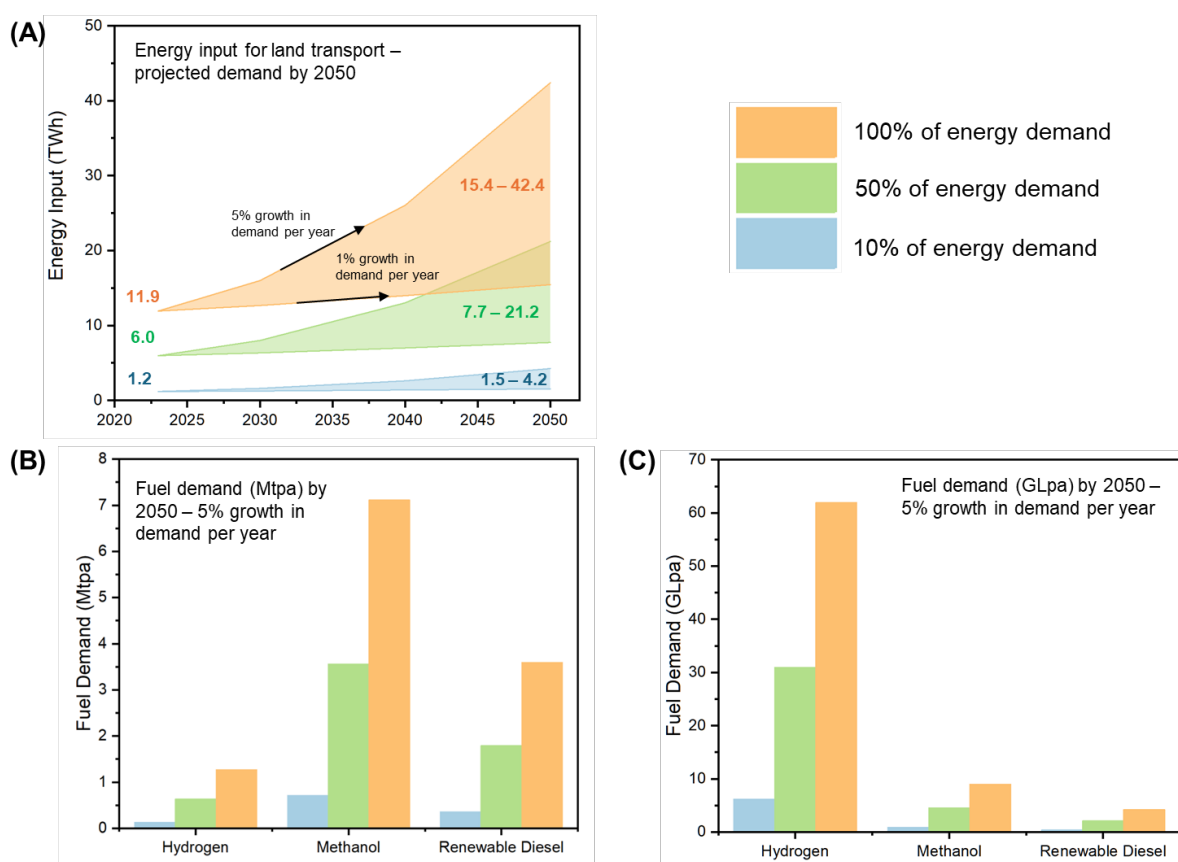


**FIGURE 6. ESTIMATED RENEWABLE DIESEL REQUIREMENT FOR ON-DEMAND ELECTRICITY GENERATION APPLICATIONS. THE DEMAND FOR METHANOL IS ESTIMATED FOR (A) SPECIFIC END-USE APPLICATIONS AND (B) UTILITY-SCALE POWER GENERATION CAPACITY.**

**Figure 6A-B** shows the estimated annual renewable diesel demands for various distributed scale applications with 30% and 100% renewable diesel replacement. For example, blending 30% renewable diesel for providing electricity to hospitals would require up to 153 tpa, whilst delivering 100% of electricity production would require 510 tpa of renewable diesel. In addition, **Figure 6C-D** illustrates the renewable diesel requirements for different sizes of diesel generators, ranging from small-scale (10 – 100 kW) to medium-scale (500 – 1,000 kW) to utility/grid-scale (5,000 – 10,000 kW) with varying blending ratios. Using 100% renewable diesel, demand for large-scale generators could reach up to 30 ktpa. The PICTs have a substantial opportunity to deploy renewable diesel as a drop-in fuel replacement to reduce emissions from decentralised diesel power generation.

## 3.2. Land Transport

In **Report A**, it was determined that the present fossil fuel demand for land transport in the PICTs is around 11.9 TWh/yr. Considering scenarios where fuel demand grows at 1 – 5% per year (**Figure 7A**), this demand could potentially reach 15 – 42 TWh by 2050, which could be partially, or potentially even wholly, satisfied through the use of renewable fuels, including hydrogen, methanol, and renewable diesel. Conversely, replacing only 10% of fossil fuel demand in this sector (with direct use of BEVs addressing the great majority of present liquid fuel use) would require between around 1.5 – 4.2 TWh of renewable fuels. For example, completely replacing the current fossil fuels for land transport applications with drop-in replacements like renewable methanol could require up to 7.1 Mtpa by 2050 (**Figure 7B**) or around 5 GLpa of renewable diesel (**Figure 7C**).

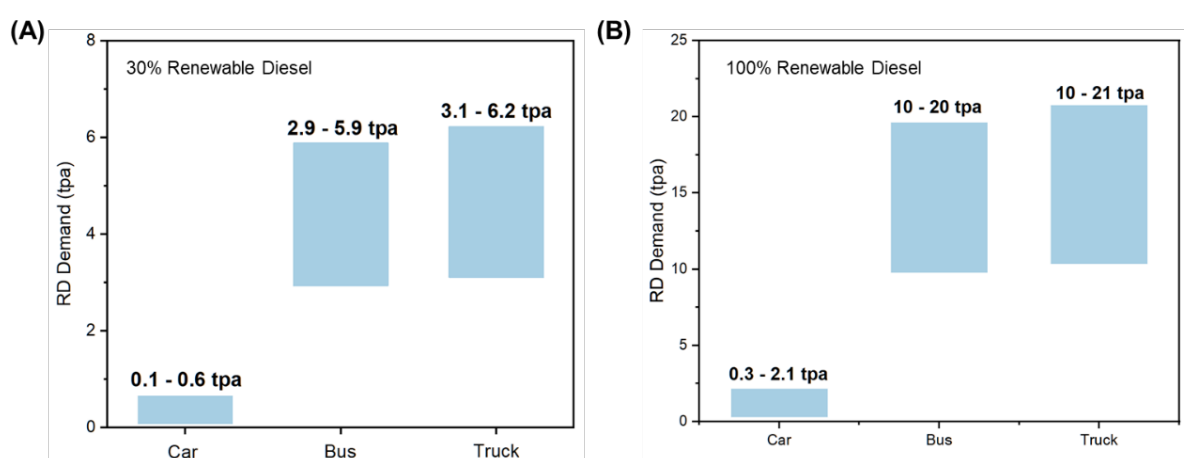


**FIGURE 7. EQUIVALENT DEMAND FOR RENEWABLE FUELS TO FULFIL LAND TRANSPORT ENERGY NEEDS OF THE PICTs. HERE (A) REPRESENTS THE GROWTH IN FUTURE ENERGY DEMAND FOR LAND TRANSPORT, ASSUMING A 1-5% GROWTH PER YEAR SCENARIO. WHEREAS (B) AND (C) REPRESENT THE EQUIVALENT DEMAND FOR SYNTHETIC FUELS TO COMPLETELY REPLACE INCUMBENT FOSSIL FUELS ON A MASS (MTPA) & VOLUME (GLPA) BASIS BY 2050 (ASSUMING A 5% INCREASE IN DEMAND PER YEAR)**

**H<sub>2</sub> Use for Land-based Mobility:** Hydrogen fuel cell electric drive trains have been commercialised for use in cars, trucks, buses, and specialised vehicles like forklifts, etc. To support hydrogen-based mobility, large-scale production hubs could supply refuelling stations with specialised use cases, including heavy-duty transport, public transportation, or in the regional cargo/supply chain. However, there are significant challenges, including the cost and social acceptance of large-scale replacement of diesel fleets with fuel cell vehicles, the high cost of hydrogen production and the need for more infrastructure to support its distribution and refuelling. Provided these can be adopted in the PICTs,

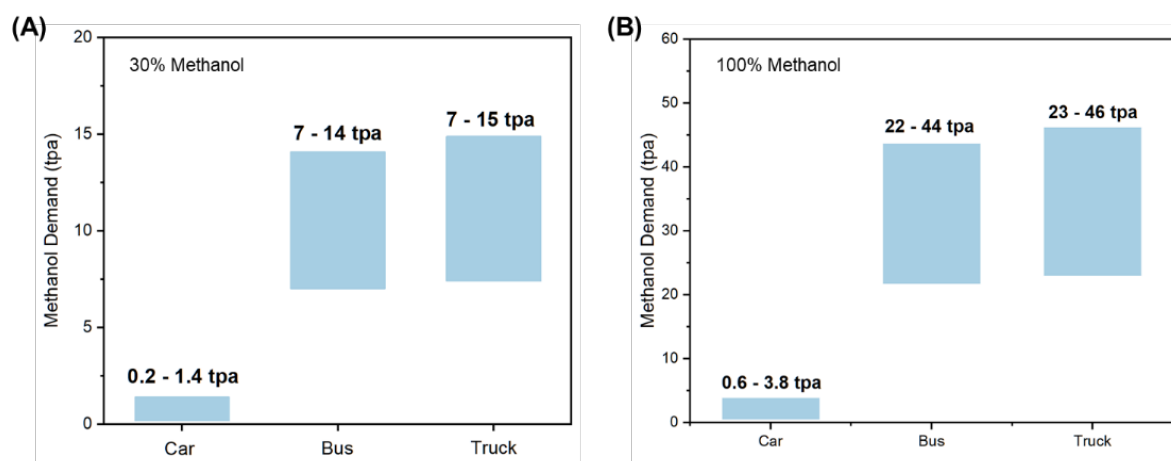
operating a fuel cell bus and truck could require up to 3.6 and 2.9 tpa of hydrogen, respectively.

**Renewable Diesel Use for Land-based Mobility:** Renewable diesel presents a more straightforward solution as a drop-in fuel replacement in existing internal combustion engines for various land transport vehicles. **Figure 8** estimates the renewable diesel requirements for passenger cars and heavy-duty vehicles, including buses and trucks, with different fuel blends. Depending on the renewable diesel blend and the distance travelled per year, the annual fuel demand for a car, bus, and truck could reach 2,500 L (2.1 tpa), 23,500 L (20 tpa), and 25,000 L (21 tpa), respectively. Implementing renewable diesel to substitute conventional fossil diesel partially or fully in land transportation allows the sector to decarbonise without necessitating modifications to existing vehicle engines, albeit at the cost of additional energy conversion losses and expenses and the requirement for sustainable sources of carbon in the production of this drop-in fuel.



**FIGURE 8.** ESTIMATED RENEWABLE DIESEL DEMAND FOR DIFFERENT MODES OF LAND TRANSPORT. HERE, THE RENEWABLE DIESEL DEMAND IS REPRESENTED FOR VARYING RATIOS OF BLENDING, INCLUDING (A) A 30% BLEND WITH FOSSIL DIESEL AND (B) A 100% SHIFT TO RENEWABLE DIESEL.

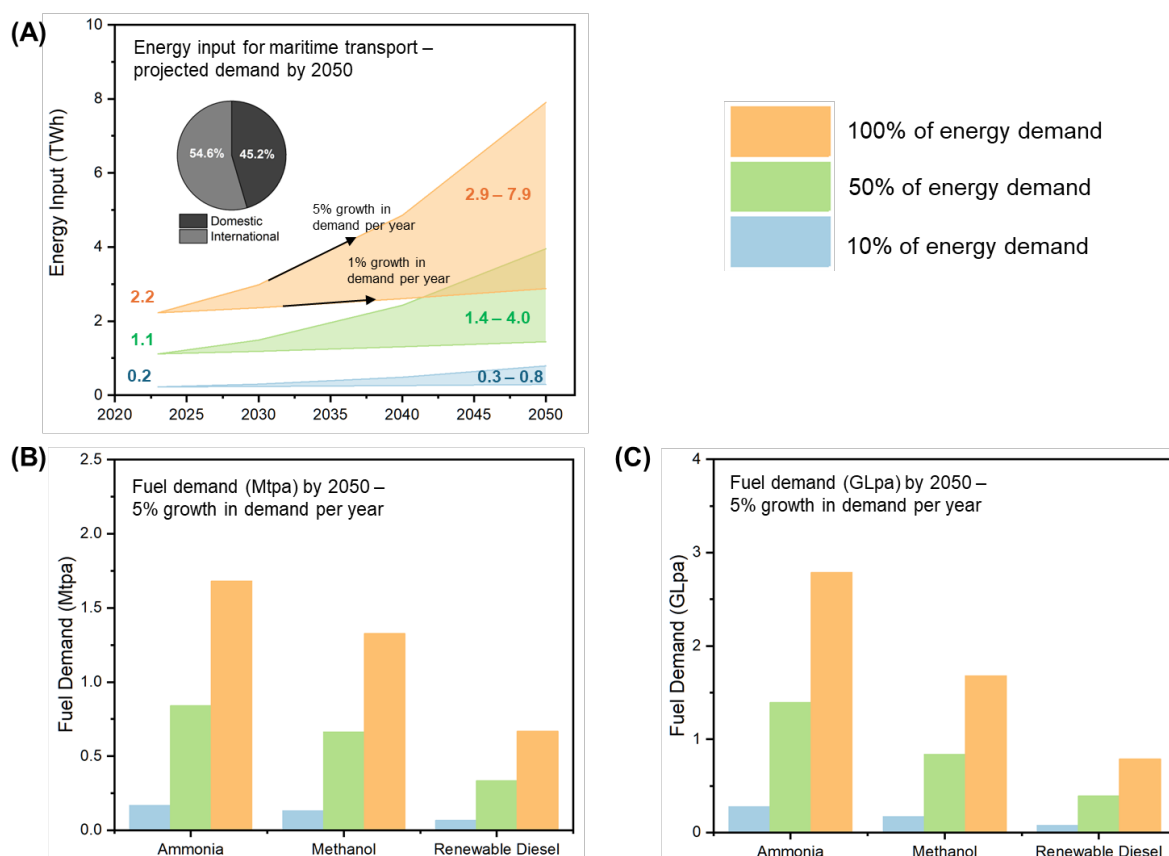
**Methanol Use for Land-based Mobility:** Methanol can also be used as a transport fuel; **Figure 9** estimates the methanol quantity required for various end-use applications.



**FIGURE 9.** ESTIMATED METHANOL DEMAND FOR DIFFERENT MODES OF LAND TRANSPORT. HERE, THE METHANOL DEMAND IS REPRESENTED FOR VARYING RATIOS OF BLENDING, INCLUDING (A) A 30% BLEND WITH FOSSIL DIESEL AND (B) A 100% SHIFT TO METHANOL.

### 3.3. Maritime Transport

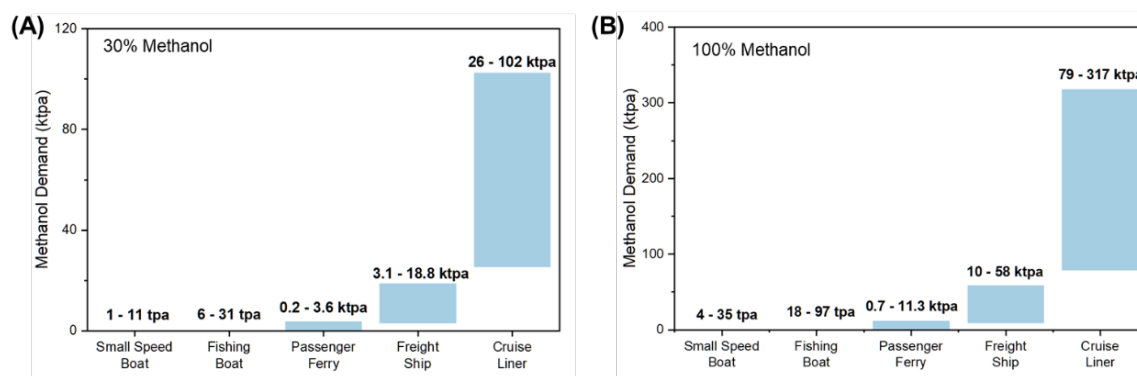
Analysis in **Report A** determined that the total fossil fuel demand for maritime transport in the PICTs is around 2.2 TWh. Around 1.0 TWh (45%) of this total is used in domestic transport, whilst 1.2 TWh (55%) is used in international fuel bunkering. Considering scenarios where fuel demand grows at 1 – 5% per year (**Figure 10A**), this demand could potentially reach 2.9 – 7.9 TWh by 2050, which could be partially or wholly satisfied through the use of renewable fuels, including ammonia, methanol, and renewable diesel. For context, completely replacing fossil fuels for maritime transport applications with renewable ammonia could require up to 1.7 Mtpa by 2050 (**Figure 10B**). In comparison, 1.5 Mtpa of methanol and 1 GLpa of renewable diesel would be required.



**FIGURE 10.** EQUIVALENT DEMAND FOR RENEWABLE FUELS TO FULFILL MARITIME SECTOR ENERGY NEEDS OF THE PICTs. HERE, **(A)** REPRESENTS THE GROWTH IN THE FUTURE ENERGY DEMAND FOR MARITIME TRANSPORT, ASSUMING A 1-5% GROWTH PER YEAR SCENARIO. WHEREAS **(B)** AND **(C)** REPRESENT THE EQUIVALENT DEMAND FOR SYNTHETIC FUELS TO COMPLETELY REPLACE INCUMBENT FOSSIL FUELS ON A MASS (MTPA) & VOLUME (GLPA) BASIS BY 2050 (ASSUMING A 5% INCREASE IN DEMAND PER YEAR).

**Methanol Use as a Maritime Fuel:** Renewable methanol shows considerable promise in decarbonising the maritime sector in the PICTs. Maritime engine manufacturers such as MAN Energy and Wärtsilä are commercialising methanol-ready engines.<sup>20,21</sup> A key advantage of methanol use is the considerably less SO<sub>x</sub> and NO<sub>x</sub> emissions compared to typical marine fuels such as heavy fuel oil (HFO) or ammonia. Moreover, engine modifications can also allow the blending of methanol with diesel. Due to the low volumetric density of methanol (4.3 kWh/L) compared to marine fuels such as HFO (11.0 kWh/L), there would be a requirement to develop and upgrade fuel storage facilities and distribution networks in the PICTs.





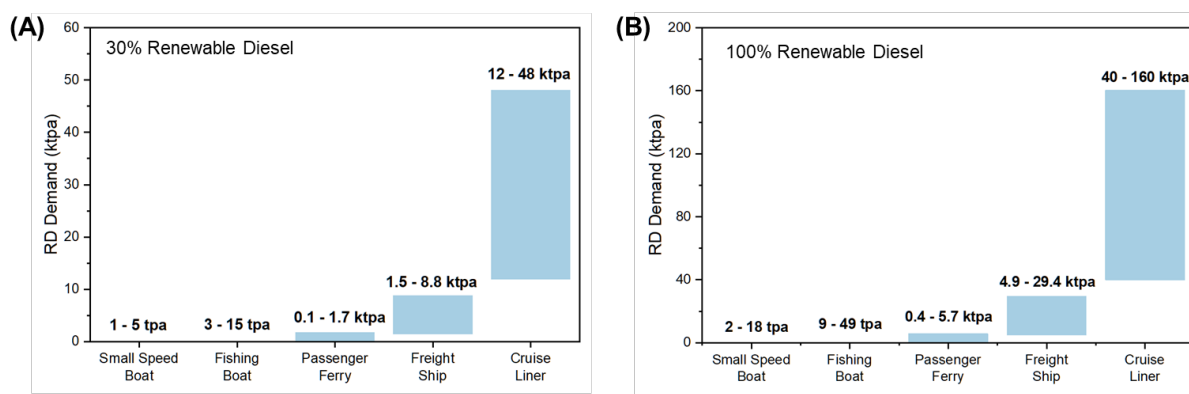
**FIGURE 11.** ESTIMATED METHANOL DEMAND FOR DIFFERENT MODES OF MARITIME TRANSPORT. HERE, THE METHANOL DEMAND IS REPRESENTED ASSUMING (A) A 30% BLEND WITH DIESEL AND (B) A 100% SHIFT TO METHANOL.

**Figure 11** summarises the demand for methanol to substitute fossil fuel, partially or entirely, for different maritime transport vehicles, including small speed boats, fishing boats, passenger ferries, freight ships, and cruise liners. For example, we estimate that a small fishing vessel run on 100% methanol could require up to 97 tpa when operating for 12 hours a day, while a cruise liner could require over 300 ktpa.

**Ammonia Use as a Maritime Fuel:** Ammonia is also a promising solution for decarbonising some of the region's maritime sectors. When ammonia is used as a fuel source, engine modification or replacement is required. Ammonia engines are currently being developed and demonstrated, revealing the benefits of partial or complete ammonia substitution in maritime transport. We estimate that between 60 and 315 ktpa of ammonia would be required for a freight ship and cruise liner, respectively. However, the safety concerns and the specialised storage, fuel handling system and engines are necessary for ammonia may lead to its use primarily in larger vessels and cargo vessels only; however, passenger maritime transport such as passenger ferries or cruise liners has been analysed here for comparison purposes to other low-carbon fuels. A key reason the region might gravitate towards ammonia fuel for maritime would be the widespread global uptake of this technology for international shipping, requiring, in some cases and indeed facilitating the deployment of the technology within the region.

**Renewable Diesel Use as a Maritime Fuel:** Renewable diesel could serve as a potential drop-in fuel replacement without requiring any engine modifications in maritime crafts, thus facilitating the industry's immediate decarbonisation, given that most ships in the region are small vessels operated with diesel engines. **Figure 12** summarises the renewable diesel demand to substitute fossil fuel, partially or entirely, for different maritime transport vehicles, including small speed boats, fishing boats, passenger ferries, freight ships, and cruise liners. Depending on the engine capacity, the operational hours per year, and the blend of renewable diesel, the demand can range from up to 50 tpa for a small fishing boat to up to 160 ktpa for a large cruise liner.

It is worth noting that using renewable diesel in PICTs maritime transport can capitalise on existing diesel storage and distribution infrastructure, optimising logistical efficiency and minimising implementation barriers. The PICTs can either self-produce renewable diesel using local resources or acquire renewable diesel from neighbouring countries to meet regional demand. This potential for regional production empowers the PICTs to take control of their decarbonisation efforts.



**FIGURE 12. ESTIMATED RENEWABLE DIESEL DEMAND FOR DIFFERENT MODES OF MARITIME TRANSPORT. HERE, THE RENEWABLE DIESEL DEMAND IS REPRESENTED ASSUMING (A) A 30% BLEND WITH FOSSIL DIESEL AND (B) A 100% SHIFT TO RD.**

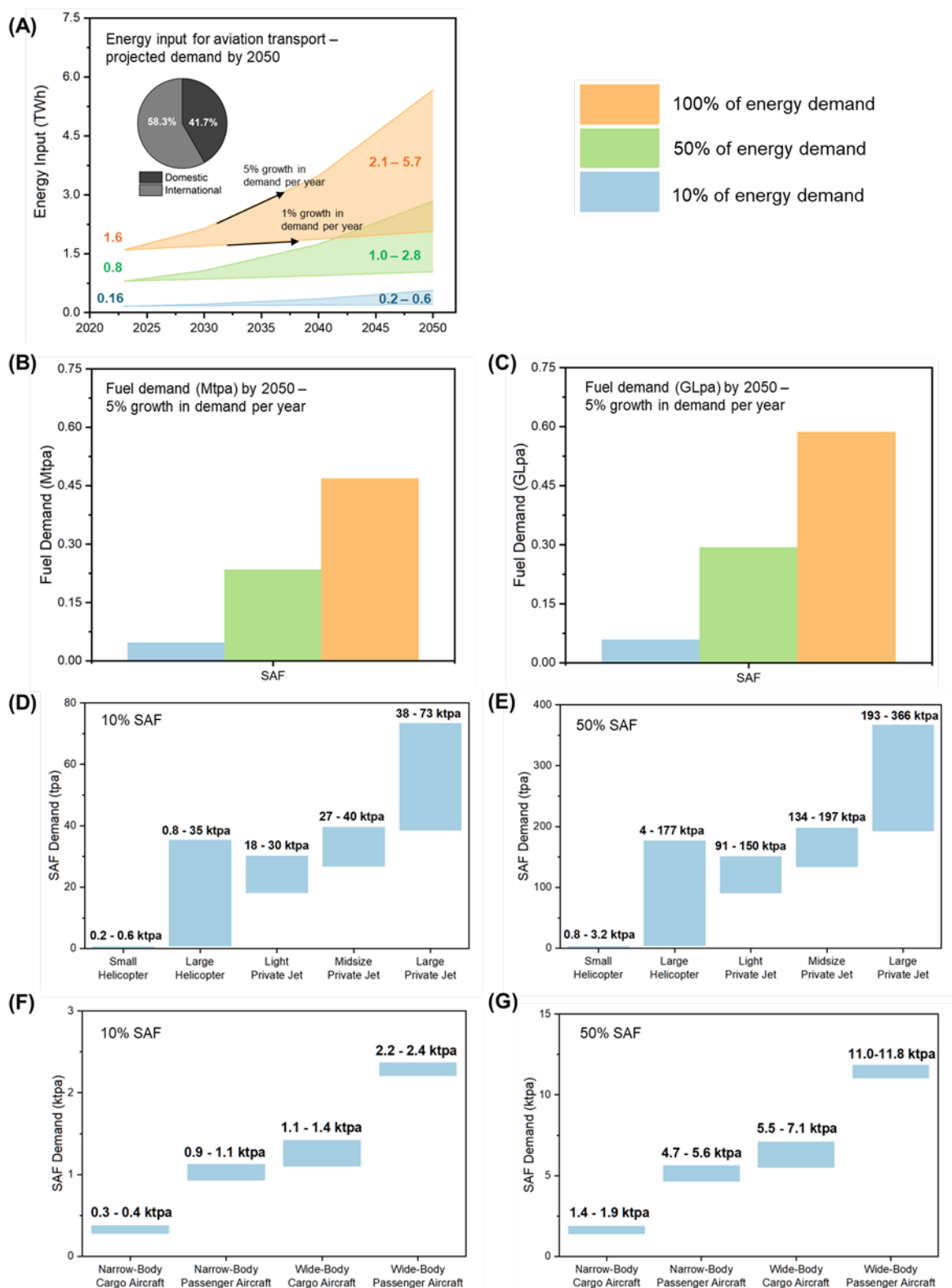
A regional analysis of the types of ships operating in the region reveals that most of the ships are small ships, such as fishing vessels, ferries, and high-speed crafts. These ships, which can be either electrified or converted to renewable diesel, present a clear pathway for the industry's transition. A recent analysis by the UNSW team on major high-capacity ships in the region >100 DWT found over 300 ships actively operating in the region (not including international ships).<sup>xii</sup> These are high-capacity and heavy-duty ships used for freight and bulk loads, and therefore, they would require specialised fuels such as ammonia, methanol, and renewable diesel. Almost 100 of these ships have ~ a 135 DWT capacity and can be operated using diesel engines that can be shifted to renewable diesel. In comparison, over 50 ships are 1,000 DWT and requiring over 200 tpd of fuel. Reflecting a market for heavy-duty engines that can be turned into ammonia or methanol engines. While the present international bunkering account for over 1.2 TWh of energy per year, which is equivalent to ~0.3 Mtpa of ammonia and 0.2 Mtpa of methanol, that could rise to 0.8 and 0.6 Mtpa, respectively (assuming a 5% increase in demand per year).

### 3.4. Aviation Transport

Analysis in **Report A** determined that the total energy demand for aviation transport in the PICTs is around 3.2 TWh. Around 1.3 TWh (42%) of this total is used for servicing domestic flights, whilst 1.9 TWh (58%) is used for international operations. Considering scenarios where aviation fuel demand grows at 1 – 5% per year (**Figure 13**), the demand for SAF could reach 2.1 – 5.7 TWh by 2050, noting that blending limits vary from 10% to 50%, depending on the production pathway.<sup>22</sup> At a blend of 50% SAF, small jets could require around 90 – 370 tpa. Commercial aviation, encompassing both cargo and passenger aircraft, has a higher magnitude of SAF demand due to the larger aircraft size and longer flight distances compared to general aviation. The highest demand is seen for wide-body passenger aircraft, which could require around 12 ktpa of SAF at a 50% blend. In practice, over the long run, some short-haul domestic aviation may be able to be directly electrified. Still, long-haul aviation is highly likely to require SAF due to the ease of transition. The PICTs can look to establish a joint SAF supply chain with neighbouring countries such as Australia, Indonesia, and Singapore, where SAF initiatives are already growing.<sup>23</sup> For example, the Asian Development Bank is funding a feasibility study for Fiji Airways and Fiji Sugar Corporation to produce ethanol from sugarcane and cassava and

<sup>xii</sup> <https://apvi.org.au/solar-research-conference/wp-content/uploads/2023/12/Santagata-E-Clean-fuels-for-maritime-decarbonisation-in-Pacific-Island-Countries-and-Territories.pdf>

SAF.<sup>24</sup> In implementing SAF (either producing locally or importing), the PICTs could make current storage and distribution networks available to the aviation sector. However, this would have to be assessed in detail.



**FIGURE 13. EQUIVALENT DEMAND FOR SAF TO SUPPLY AVIATION SECTOR ENERGY NEEDS OF THE PICTs. HERE, (A) REPRESENTS THE GROWTH IN THE FUTURE ENERGY DEMAND FOR THE AVIATION SECTOR, ASSUMING A 1-5% GROWTH PER YEAR SCENARIO. WHEREAS (B) AND (C) REPRESENT THE EQUIVALENT**

### 3.5. Industrial Demand

From an industrial perspective, hydrogen and derivatives can then be applied to support a wide range of energy needs. Hydrogen can be used as a means of large-scale energy storage to supplement industries' renewable electrification. A key market for this would be to support the decarbonisation of the mining industry, such as the nickel industry in New Caledonia or the gold mines in PNG. As highlighted in *earlier analysis*, the nickel mines/processing facilities in New Caledonia account for over 70% of the energy footprint, predominantly from diesel generators. While efforts are being conducted to displace diesel/coal-powered generators with solar/wind power<sup>25</sup>, a 100% transition to these energy sources would require intermediate energy storage. While BESS systems have been installed, deploying H<sub>2</sub> and derivatives could create a multifaceted opportunity serving as a source of energy backup and long-term energy storage for on-demand power generation but also to serve the refuelling demand of the mining equipment and processing facilities and facilitate the greater supply of alternate fuels for the maritime and land transport sector.

### 3.6. Summary

Altogether, as summarised in **Table 4**, a 40 TWh/yr of imported fossil fuel demand can be displaced by H<sub>2</sub> and derivatives across the PICTs. By accounting for the differences in energy density (energy content of H<sub>2</sub> and derivatives relative to fossil fuel counterpart) and conversion efficiency (the efficiency of end-use technology such as fuel cells or engines)<sup>xiii</sup>. This demand would translate to ~1.1 Mtpa of H<sub>2</sub>, 5.3 Mtpa of ammonia, 6.2 Mtpa of methanol, 3.6 GL/y (3.1 Mtpa) of renewable diesel, and 0.3 GL/yr (0.2 Mtpa) of SAF. Overall, these demands for H<sub>2</sub> and derivatives are achievable, given the availability of feedstock resources across the PICTs and the maturity/scalability of H<sub>2</sub>/derivative technologies.

**TABLE 4. REVISED DEMAND FOR H<sub>2</sub> AND DERIVATIVES FOR DISPLACING PICT'S IMPORTED FOSSIL FUELS**

Sectoral Energy Cons (TWh/yr)	Equivalent Fuel Demand of Hydrogen and Derivative by 2050				
	H <sub>2</sub> Demand (Mtpa)	Ammonia Demand (Mtpa)	Methanol Demand <sup>xiv</sup> (Mtpa)	RD Demand (GL/year) <sup>xv</sup>	SAF Demand (GL/year)
<b>Total Energy Consumption</b>					
~ 40	1.1	5.3	6.2	3.6 (3.1)	0.3 (0.2)
<b>Power Generation</b>					
22.4	0.7	4.8	3.8	2.2 (1.9)	-
<b>Land Mobility</b>					
11.9	0.4	-	2.0	1.2 (1.0)	-
<b>Domestic Maritime Sector</b>					
1.0		0.2	0.2	0.1 (0.1)	-
<b>International Maritime Sector</b>					
1.2		0.3	0.2	0.1 (0.1)	-
<b>Domestic Aviation Sector</b>					
1.3	-	-	-	-	0.1 (0.1)

<sup>xiii</sup> Refer to **Appendix A** for calculations and assumptions

<sup>xiv</sup> Methanol demand values are estimated assuming a 100% displacement of fossil fuels (not as a blend with diesel or gasoline etc).

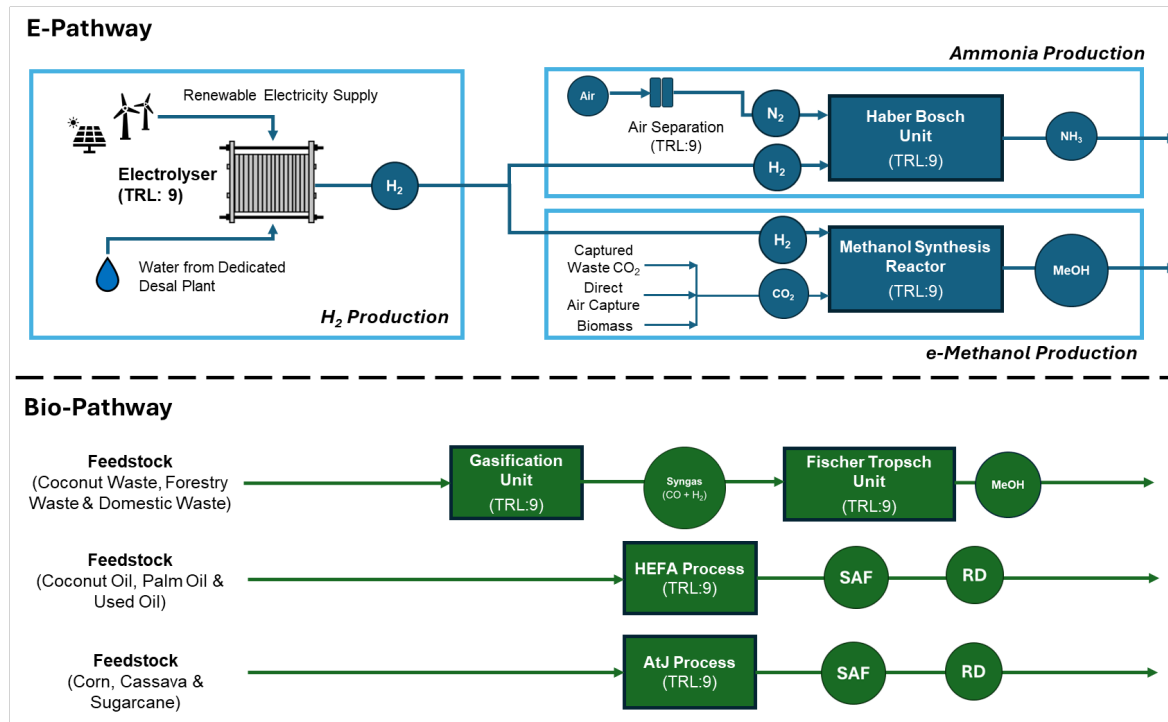
<sup>xv</sup> The demand for RD and SAF is primarily reflected in GL/yr as they are generally costed and stored per volume, for direct comparison of mass the equivalent tonnage is shown in brackets.

International Aviation Sector					
1.9	-	-	-	-	0.2 (0.1)

Yet in practice, as highlighted earlier, H<sub>2</sub> and derivatives are a new frontier for the PICTs, with several barriers to entry. Primarily, there is a lack of regional expertise and experience with H<sub>2</sub> and derivative technology, which is a readiness challenge that manifests both in the economic outlook and in energy policy and infrastructural compatibility. The following sections of the report then dive deeper into aspects of the H<sub>2</sub> and derivative value chains within the PICT context, highlighting the opportunity cost of shifting to these alternate fuels (compared to current fossil fuel use) both in terms of economics and infrastructural changes required.

## 4. Economic Modelling of H<sub>2</sub> & Derivatives

This section assesses the levelised cost of producing green hydrogen and derivatives. **Figure 14** illustrates the schematics of the modelled production pathways.



**FIGURE 14. SCHEMATICS OF THE ANALYSED H<sub>2</sub> AND DERIVATIVE PRODUCTION PATHWAYS<sup>xvi</sup>**

**Note:** Accompanying tools for assessing these production opportunities across the Pacific are being developed and will be made available through the project website.

The pathways are elaborated below:

- E-Pathway:** This pathway starts with renewable hydrogen generation, for which dedicated electrolyzers with standalone solar and wind power plants are considered. Subsequently, for ammonia generation, the hydrogen supply from the electrolyzers is then coupled with the Air Separation Unit (ASU) for nitrogen and the Haber Bosch Unit (HBU). Similarly, for methanol generation, the generated H<sub>2</sub> is then coupled with CO<sub>2</sub> sources (herein, we consider a reflective cost range of CO<sub>2</sub> sources, including captured waste CO<sub>2</sub> from industry/power generation point sources, Direct Air Capture – DAC or from biomass gasification) and fed to a methanol synthesis reactor. Moreover, given the disparity of solar and wind generation data across the region, representative solar and wind traces for modelling the electrolyser capacity factors were developed using historical data. The underlying methodology for the assessment is elaborated below in **section 4.1**.

<sup>xvi</sup> Refer to **Report B** for a more detailed overview of these pathways.



- **Bio-Pathway:** In comparison, bio-pathways are based on the conversion of biomass/waste feedstocks such as coconut, forestry and domestic waste, oils such as coconut oil, palm oil, and used oils, as well as crops such as corn, cassava, and sugarcane, which are available across the PICTs region (elaborated later in section 4.2). Of these, coconut, domestic, and forestry waste can be converted to bio-methanol through gasification.<sup>26,27</sup> Moreover, the syngas produced from the gasification of these feedstocks can then be converted to sustainable aviation fuel (SAF) and renewable diesel (RD) through the Fischer-Tropsch process.<sup>30,31</sup> Crops like corn, cassava, and sugarcane are suitable feedstocks for SAF and RD production through the alcohol-to-jet (AtJ) process.<sup>30–32</sup> Oil-based feedstocks, including coconut oil, palm oil, and used oils, can be converted to SAF and RD through the HEFA (hydro-processed esters and fatty acids) pathway.<sup>30–32</sup> In contrast, all these feedstocks are identified as technically suitable feedstocks for biofuel production and are currently recognised in the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) framework.<sup>33</sup>; not all feedstocks meet sustainability standards. Under the CORSIA framework, byproducts, wastes, and residues (e.g., coconut waste, forestry residue, domestic waste, sugarcane bagasse, and used oils) are entitled to an Indirect Land Use Change (ILUC) value of zero on the life cycle emission value. However, primary and co-products like palm oil, coconut oil, sugarcane, and corn may have sustainability constraints due to the potential land use change and competition with food sectors.

## 4.1. E-fuels

The following sections estimate the levelised cost of producing hydrogen from electrolysis driven by renewable energy supply and its subsequent conversion to ammonia through a Haber Bosch process (with N<sub>2</sub> sourced from air) and methanol reactor (with waste CO<sub>2</sub> sourced from bioresources)

### Hydrogen Production

Assessment of the hydrogen production costs was conducted at different electrolyser scales (1 MW, 10 MW, 50 MW, 100 MW, and 500 MW), using New Caledonia, Fiji, Samoa, Vanuatu, Solomon Islands, and PNG as a representative case study of the PICTs.

### Cost Assumptions

**Capital Costs of the Electrolyser:** The capital costs considered the cost of the electrolyser system and the integrated solar and wind farms; these costs were adopted from recent global estimates provided by IRENA and IEA. The recent IEA review on the Global Hydrogen Economy suggests that the weighted average cost of electrolyzers is in the order of US\$1,640/kW, assumed at a 1 MW scale, with an expectation that the costs will fall to US\$610/kW by 2030.<sup>1</sup>

**Note:** These capital costs reflect the cost of equipment. The additional cost of procurement, supply to the Pacific, and installation at the site would have to be considered. Based on the stakeholder discussions, these extra costs could be up to three times the cost of equipment. A sensitivity analysis is conducted to estimate the impact of the baseline equipment and additional costs. From a project development perspective, we

**Economies of Scale:** To account for the economies of scale, the following cost scale index approach, shown below, was applied. The method uses a scale index-based logarithmic function to estimate the cost ( $C_b$ ) at any given scale ( $S_b$ ) by scaling up or down the reference cost ( $C_a$ ) at a known scale ( $S_a$ ) against a scale factor ( $f$ ). Studies of this issue

suggest a scale factor of 0.7 for <5 MW electrolyser scale and 0.9 for larger scale systems.<sup>2</sup>

$$C_b = C_a \times \left(\frac{S_b}{S_a}\right)^f$$

**Financing Costs:** The Weighted Average Cost of Capital (WACC) is used to account for financing costs. It represents the average cost of capital that can be leveraged from a mix of equity—and debt-based investments.<sup>34</sup> For perspective, a lower WACC is preferred as it means the equity and debt investment is made under low associated risk, which will result in a higher return.<sup>35</sup> Herein, an after-tax WACC of 10% was considered to account for the high risks of an investment in hydrogen from the PICTs context, given that such projects are the first of their kind, owing to a lack of regional expertise/technology.<sup>34,36</sup> There is also significant competition for the required investment as it can be used to address other essential economic needs in the region. The same WACC assumptions were applied to the solar and wind farms. Nevertheless, a sensitivity analysis was conducted to reflect the impact of WACC on overall costs. Note that commercial finance costs are typically high across the Pacific due to a wide range of factors, including the region's small and vulnerable economies and lack of sophisticated finance sectors. However, there are also opportunities for the region's partner organisations to assist in lower-cost finance for clean energy projects. A region-wide regulated framework for distributing incentives and supportive financing can be employed across the region to create a conducive economic environment for such projects.

**Operation and Maintenance Costs:** The operating costs include the electrolyser operating and maintenance (O&M) costs. An O&M cost of 2.5% of the capital cost per year is considered.<sup>37</sup> In addition, the electrolyser stack needs to be replaced after a set period due to efficiency losses. Generally, a cost equivalent to 40% of the electrolyser equipment cost is considered, and the IEA suggests an electrolyser lifetime of 50,000 aggregate operational hours before they need to be replaced.<sup>1</sup>

**Water Costs:** In addition, water use needs to be considered from the operational perspective. Here, a water requirement of 20 L/kg of H<sub>2</sub> is assumed. The retail price of commercial RO water plants is adopted to account for the water supply costs. A portable desalination RO plant with a capacity of 2,000 L/day currently costs an estimated US\$12k.<sup>38</sup>

**Note:** As reported in **Report B**, high-quality water deionised water is required for operating electrolysers with low conductivity (<1 µs/cm). Given the strong competition and strict provision for freshwater sources, dedicated desalination plants would be a particular option. This could also benefit the greater region, as the desalination plants can be scaled up to provide water for the area as well as hydrogen production, given that small-scale RO plants are generally challenging to operate. While at scale, these plants would be costly to build and manage given the energy required to drive them, from a hydrogen perspective, the cost of water is not high, as under even a high cost of water procurement scenario (assuming ten times the price above), the overall unit cost of hydrogen (US\$/kg) would increase by 3%.

**Energy Costs:** For the analysis herein, it is assumed that dedicated standalone solar/wind generators would be deployed to drive the electrolysers. Recent estimates from IRENA were adopted to estimate the cost of these newly built power plants. Accordingly, the cost of solar PV farms in the order of US\$880/kW and onshore wind farm cost of US\$1,280/kW

were adopted. In addition, an O&M cost of US\$7.5/kW/year and US\$50/kW/year for solar PV and wind farms are adopted, respectively.<sup>39</sup>

**Note:** Similarly to the electrolyzers, these capital costs consider the cost of equipment, the additional cost of procurement, supply to the Pacific and installation at the site would have to be considered. These are accounted for in the sensitivity analysis.

**Renewable Energy Profiles:** The solar and wind outputs were modelled using Renewables Ninja.<sup>40</sup> This is an open-source web package tool (licensed under the Creative Commons attribution-non-commercial 4.0 International (CC BY-NC 4.0) license) that simulates the hourly power output from wind and solar power plants anywhere in the world. The tool uses weather data from global reanalysis models and satellite observations (NASA MERRA reanalysis and CM-SAF's SARA Dataset). The solar irradiance data and the wind speeds are then converted to hourly power outputs (MWh/MW of capacity) through custom models integrated within the Renewable Ninja.

For details on the solar and wind data used in the study, refer to the blue box (Solar and Wind Data) below. Note that for the cost modelling herein, we use the average renewable energy capacity factors for a high-level estimation and analysis. However, the modelling tools that will be made available to the region can do detailed modelling based on hourly power supply, as the production schedule of these generators is essential in optimising the operation of electrolyzers and downstream conversion units.

**Hydrogen Yield:** The hydrogen yield was then estimated by correlating the renewable energy input (MWh) with the electrolyzer efficiency (kWh/kg). As per IEA specifications, an electrolyzer efficiency of 65% LHV or 51 kWh/kg was adopted.<sup>1</sup> The renewable energy inputs from the dedicated power plants were modelled based on the regional energy profiles developed through Renewable Ninja. Comparisons between the best and worst-performing sites were conducted to reflect the impact of the differences in solar and wind profiles. Different scenarios of having a 100% solar, 50-50% mix of solar and wind and 100% wind power supply were considered.

**Levelised Cost of Hydrogen:** The estimated capital and operating costs are then integrated to calculate the levelised cost of hydrogen (LCOH – US\$/kg), as shown below:

$$\text{LCOH} \left( \frac{\text{US\$}}{\text{kg}} \right) = \frac{\text{CRF} \times \text{Capital Cost} + \text{Operating Costs}}{\text{Hydrogen Yield} \left( \frac{\text{kg}}{\text{year}} \right)} \quad (1)$$

Here, CRF is the capital recovery factor, and the CRF is used to annuitise the capital cost and distribute it into a present value of returns needed to recover the capital costs.

The CRF is calculated as a function of the WACC and project lifetime, as shown below:

$$\text{CRF} (\%) = \frac{\text{WACC} \times (1 + \text{WACC})^n}{(1 + \text{WACC})^n - 1} \quad (2)$$

Here, n represents the expected economic (financing) lifetime of the project in years.

**Table 5** summarises the parameters used for the analysis.

## Solar and Wind Data

The regional solar and wind profiles were adopted using the online resource Renewable Ninja. Renewable Ninja uses empirical formulas to correlate the regional solar insolation and wind speed data with the efficiency of solar PV and turbines to represent the MWh of energy produced for an MW of installed capacity across the year.

For the analysis herein, the solar and wind data for the major countries across the PICTs, including Fiji, Samoa, New Caledonia, Vanuatu, Solomon Islands and PNG, were adopted as a representative case study of the Pacific region.

Hourly time series profiles for solar and wind were obtained for each country between 2010 and 2023. From this data, a representative year was chosen based on the mean of average annual capacity factors from the available data. Hourly data corresponding to the representative year was used as part of the baseline inputs for the techno-economic models, which calculate production profiles over the lifetime of renewable fuels projects.

**TABLE 5. HYDROGEN PRODUCTION COSTING ASSUMPTIONS**

Parameter	Value
<b>Electrolyser Parameters</b>	
Capacities	1 MW, 10 MW, 50 MW, 100 MW and 500 MW
Efficiency	65% LHV or 51 kWh/kg (0.02 t/MWh)
Water Consumption	20 L/kg
Electrolyser Costs	US\$1,640/kW
Electrolyser Economies of Scale	Scale index of 0.7 for <5 MW and 0.9 for larger scale systems
Electrolyser O&M Costs	2.5% of Electrolyser Capital Cost per annum
Electrolyser Lifetime	50,000 hours of operation
Electrolyser Stack Replacement	40% of Electrolyser Costs per replacement
Water Supply Costs	A desalination plant with a capacity of 2,000 L/day at a cost of US\$12k
<b>Powerplant Parameters</b>	
Powerplant Capital Costs	Solar PV: US\$800/kW and Wind Farm: US\$1,280/kW
Powerplant O&M Costs	Solar PV: US\$7.5/kW/yr and Wind Farm: US\$50/kW/yr
<b>Locational Scope</b>	
Considered Locations	New Caledonia, Fiji, Samoa, Vanuatu, Solomon Islands, and PNG
<b>Financing</b>	
WACC	10%
Lifetime	20 years

## Levelised Cost of Production Calculator

Complementary tools to evaluate the levelised cost of production (including all the considered fuels) have been developed as a resource for the PICTs. These tools will be made publicly available in due time. These tools are based on the open-source costing and modelling platform developed by UNSW Sydney, which has been extensively tested and improved through engagement and application to industrial settings.

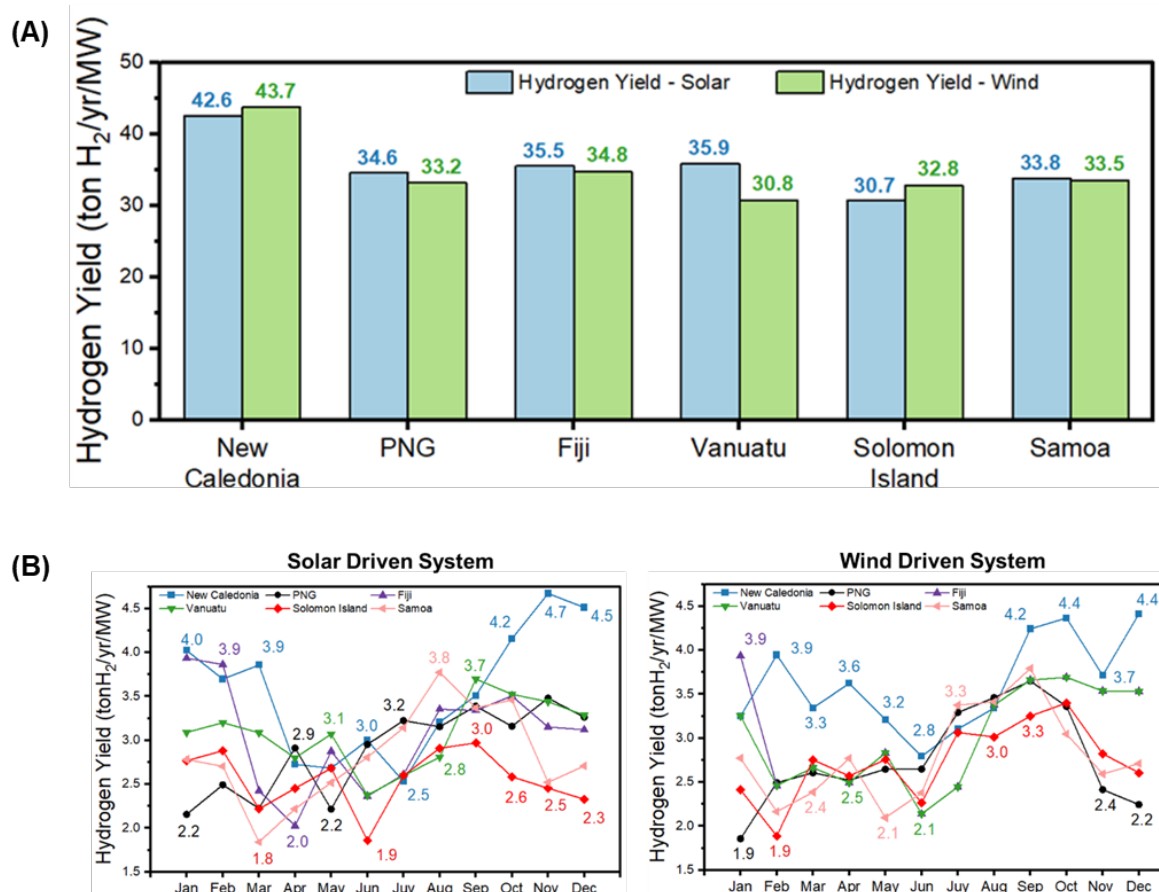
**Sensitivity Analysis:** In addition, a sensitivity analysis is conducted to illustrate a pathway to reducing the LCOH. For the sensitivity analysis, the solar-powered system at 1 MW capacity electrolyser in New Caledonia is considered the base case with the assumptions shown in **Table 5**. The sensitivity is then conducted for the following parameters and scenarios listed in **Table 6**.

**TABLE 6. ASSUMED SENSITIVITY ANALYSIS SCENARIOS FOR HYDROGEN PRODUCTION COSTS**

Sensitivity Parameter	Reasoning	Sensitivity Analysis Scenarios				
		A	B	C	D	E
Solar/Wind Mix	Reflect the impact of a hybrid solar & wind power mix	90% Solar & 10% Wind	75% Solar & 25% Wind	50% Solar & 50% Wind	25% Solar & 75% Wind	10% Solar & 90% Wind
Electrolyser Capacity	Reflect impact of economies of scale	10 MW	50 MW	100 MW	500 MW	
Electrolyser Capital Costs	Reflect the impact of equipment purchase & additional installation costs	3 x less than the base case	1.5 x less than the base case	1.5 x more than the base case	3x more than base case	
Powerplant Capital Costs		3 x less than the base case	1.5 x less than base case	1.5 x more than the base case	3x more than base case	
Electrolyser Efficiency	Reflect the impact of efficiency improvements	70% LHV	80% LHV	90% LHV		
Electrolyser O&M Costs	Reflect impact of cost of maintaining electrolyser	3%	5%	7.5%	10%	
Powerplant O&M Costs	Reflect the impact of the cost of maintaining powerplant.	1.5 x more than base case	2 x more than base case	3 x more than base case	4 x more than base case	5 x more than base case
Water Consumption	Reflect impact of electrolyser water consumption	20 L/kg	40 L/kg	60 L/kg	80 L/kg	100 L/kg
Water Costs	Reflect the impact of water supply costs.	1.5 x more than base case	2 x more than base case	3 x more than base case	4 x more than base case	5 x more than base case
WACC	Reflect on the impact of financing	9%	8%	7%	6%	5%
Project Lifetime		10 years	15 years	25 years	30 years	

**Pathway to Parity:** Finally, the estimated production costs for H<sub>2</sub> and derivatives are compared against the current global prices for the commodities that these would be substituting for when considering possible pathways to price parity. This is a very high bar to set for clean fuels, given that existing fossil-fuel-based alternatives are generally not pricing in the environmental harms that they cause. Future clean energy pathways will almost certainly need to see continuing cost reductions in clean fuels, as well as appropriate environmental regulations and taxes that price the harms of fossil fuels. As such, our discussion of parity pathways is somewhat unfair against clean fuels and, indeed, represents stretch targets.

**Hydrogen Production Potential:** **Figure 15** provides a comparison of the potential hydrogen yields across the major islands and territories in the PICTs (PNG, New Caledonia, Fiji, Vanuatu, Samoa, and Solomon Islands).



**FIGURE 15.** ESTIMATED H<sub>2</sub> PRODUCTION POTENTIAL BASED ON THE SOLAR AND WIND PROFILES OF THE MAJOR ISLANDS ACROSS THE PICTs. HERE, (A) REPRESENTS THE ANNUAL H<sub>2</sub> PRODUCTION POTENTIAL THAT IS REPRESENTED AS ANNUAL H<sub>2</sub> PRODUCTION (TON H<sub>2</sub>/YR) PER INSTALLED CAPACITY OF ELECTROLYSER (MW). THESE VALUES CAN THEN BE USED AS A REFERENCE TO ESTIMATE H<sub>2</sub> PRODUCTION CAPACITY AT ANY SCALE OF ELECTROLYSER BY MULTIPLYING THE BASELINE VALUES (TON H<sub>2</sub>/YR/MW) WITH THE GIVEN CAPACITY OF ELECTROLYSER.<sup>xvii</sup> MEANWHILE, (B) REPRESENTS THE IMPACT OF SEASONAL VARIATION ON THE H<sub>2</sub> YIELDS OF SOLAR AND WIND PROFILES.

Overall (**Figure 15A**), as expected, the yields vary based on the regional solar and wind energy profiles. Generally, amongst these PICTs, for every MW of electrolyser capacity developed, the solar-based system would generate 30.7 to 35.9 tonH<sub>2</sub>/yr installed, whereas the wind-based systems will generate 30.8 to 34.8 tonH<sub>2</sub>/yr. Amongst these significant regions, New Caledonia shows the highest yields both for solar and wind-driven systems, 42.6 and 43.7 tonH<sub>2</sub>/yr/MW. Additionally, the H<sub>2</sub> yields are more dominant for solar-driven systems than equivalent wind-driven systems (except for New Caledonia and Solomon Islands), which would be a significant advantage as new solar generation capacity will be more straightforward to build, is more distributable and can be deployed at flexible, scalable capacities compared to wind turbines.

The cumulative annual hydrogen yield provides a straightforward way to represent and compare the yields amongst the PICTs. However, as it is a cumulative aggregate, it simplifies the underlying nuances and variations in production due to seasonal changes in solar and wind profiles. To reflect this, **Figure 15B** further distributes the annual profiles into monthly resolutions (that represent the impact of seasonal variations). As observed,

<sup>xvii</sup> Note: These yields are only a high-level reflection, actual yields will vary based on various factors like variation in solar/wind profiles, changes in electrolyser's efficiency as a function of load or degradation and operational loads at which the electrolyser is or can be operated at.

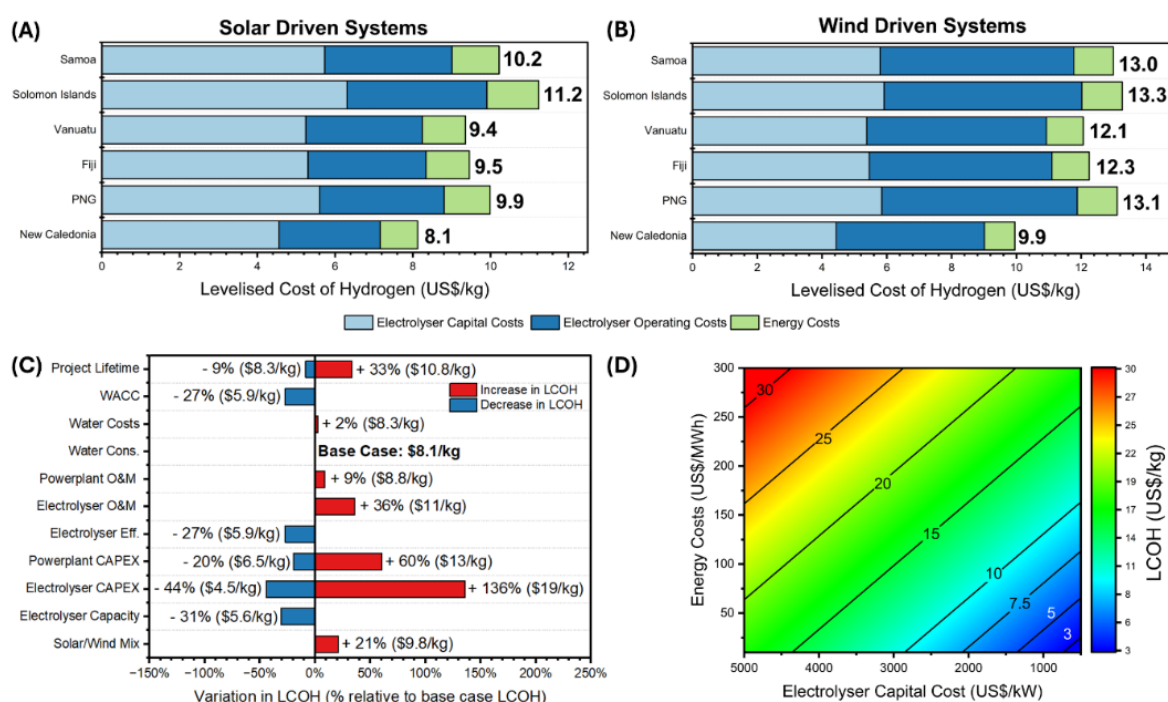


both the solar and wind yield profiles peak in the summer seasons (September to March). These profiles show that to maintain a high and consistent hydrogen supply for the bulk of hydrogen generation, the summer profiles would have to be leveraged. The capacities of the electrolyser and power supply would have to be optimised to achieve excess hydrogen supply (relative to the downstream demand) that can then be stored and used during the winter times (March to July) when the hydrogen production tails off due to the decreasing solar and wind energy throughput.

## Levelised Cost of Hydrogen Estimates

**Figure 16** shows the estimated 'base case' hydrogen production costs (LCOH) for solar PV and wind farm-driven scenarios across the major PICTS regions. Overall, for 1 MW systems, the LCOH is estimated to range between US\$8 – 13/kg (**Figure 16A-B**). Moreover, solar-driven systems are more economical than their wind counterparts; this is due to lower wind capacity factors and wind systems being costlier to build. The yield differences are also reflected in the LCOH distribution, with the higher yield regions showing the lower LCOH, with New Caledonia reflecting the lowest cost of production due to both higher solar and wind yields.

**Note:** As suggested above, these 'base case' costs are based on international equipment and installation costs. Experience suggests project costs will be considerably higher in the Pacific, and this is explored further below.



**FIGURE 16.** ESTIMATED COST OF RENEWABLE ELECTROLYSIS-BASED H<sub>2</sub> PRODUCTION IN PICTs. HERE, THE COSTS OF PRODUCTION ARE (A) ESTIMATED AT 1 MW SCALE FOR (A) SOLAR DRIVEN AND (B) WIND DRIVEN SYSTEMS OF THE MAJOR ISLANDS TO COMPARE THEIR ECONOMIC COMPETITIVENESS. AS OBSERVED, NEW CALEDONIA IS THE MOST COMPETITIVE BOTH FOR SOLAR AND WIND, FOLLOWED BY VANUATU, FIJI AND PNG. ADDITIONALLY, (C) REPRESENTS THE SENSITIVITY OF LCOH, WITH THE HIGHEST SENSITIVITY OBSERVED FOR ELECTROLYSER /POWERPLANT CAPEX, CAPACITY, EFFICIENCY AND WACC. THE LCOH IS ALSO REPRESENTED AS A (D) FUNCTION OF ELECTROLYSER CAPITAL COST & ELECTRICITY PRICE, WHICH REFLECTS THAT THE COST OF ELECTROLYSER OF US\$1,500/KW AND ENERGY PRICE OF <US\$25/MWH WOULD BE REQUIRED FOR COMPETITIVE H<sub>2</sub> PRICING (<US\$3/KG).

## Sensitivity Analysis

Further insights on the critical drivers of LOCH are reflected through the sensitivity analysis (shown in **Figure 16C**). As observed, the key drivers of the costs are the capital cost (CAPEX) of the electrolyser and the power supply. From an electrolyser perspective, the cost of equipment has been on a downward trajectory despite recent increases in prices due to the inflation cycles. The IEA predicts that the global average cost of electrolysers will fall by 60%, falling to US\$610/kW from the present US\$1,640/kW by 2030.<sup>1</sup> This decrease is to be propelled by the rising demand for electrolysers, which is causing the scale-up and optimisation of electrolyser manufacturing capacity. This will lead to the benefits of economies of scale and result in a lower cost per unit of production. Similar effects are also driving the cost of solar PV and wind turbines. IRENA estimates the cost of PV panels has decreased by 50% over the last five years; at the same time, the cost of onshore and offshore wind farms is 28% and 36%, respectively.

In addition, global investment incentives in the form of tax credits or cost offsets are being introduced to lower the LCOH. The sensitivity analysis shows that reducing the capital costs (the electrolyser and powerplant) by 1.5 times the base case will lead to a 10% to 22% decrease in LOCH, increasing to a 20% to 44% decrease in LCOH if the capital costs can be reduced by three times. Our high-level estimates show that a CAPEX subsidy of US\$65k/MW of electrolyser capacity (25% of total capital cost) would be required to reduce baseline LCOH by ~US\$1/kg. In addition, economies of scale will reduce the LCOH, and we estimate a 31% decrease in LCOH for a 500 MW capacity electrolyser facility compared to a 1 MW facility. The impact of capital costs can also be mitigated by reducing the WACC; at present, we assumed a high WACC of 10% to reflect the high risks associated with investing in the hydrogen projects, which would be a first of their kind in the PICTs. However, as these risks are reduced, and financing of the project can be done with assistance from partners, e.g., at a WACC of 5%, the LCOH will decrease by 27%.

However, as highlighted earlier, it is essential to note that these costs reflect the cost of equipment; additional costs would be incurred for installation and procurement. This would be a particular concern for the PICTs due to challenges regarding local expertise and equipment within the region. Therefore, particularly, the first projects in the area would face these challenges, as shown by **Figure 16C**, if the inclusion of installation costs increases the overall capital costs (3 times the baseline equipment costs), this would result in 60% to 136% of the base LCOH cost. Similar challenges will impact the operation and maintenance (O&M) costs; as observed, if the baseline O&M costs increase by three times, the LCOH could rise by 9% to 36%.

The capacity factor of the electrolyser is a critical factor for the costs as well. As highlighted above, this capacity factor is directly impacted by the intermittency of solar and wind generation profiles. Therefore, from an ideal cost perspective, higher capacity factors are preferred as this will lead to better capital efficiencies and lower levelised costs. Academic and industrial assessments have suggested several methods to optimise the electrolyser and power supply capacities. These include oversizing the power supply (making larger capacity solar/wind farms relative to the electrolyser), installing a BESS, and developing a high-capacity power supply through hybrid power supply from solar/wind, hydro or other renewable energy sources, amongst others. Each of these efforts, however, involves a cost-and-benefit trade-off, as firming power supply requires an additional upfront investment that needs to be balanced with the resulting boost in yield.<sup>37</sup> For example, an optimum oversize ratio of 1.25 to 1.5 times has been suggested for solar/wind farm coupled electrolysers; this would mean an additional 25% to 50% capital cost of the power

plant. In this manner, for perspective, for every MW of electrolyser capacity, oversizing would require an additional upfront capital investment of US\$1–2 million (under the IRENA estimated cost of building new solar and wind farms as provided in [Table 5](#)). In case a battery is to be added to the mix, the powerplant would have to be oversized to generate enough surplus energy that can be stored to boost electrolyser capacity factors when solar and wind generation tail off. This creates a double whammy in the form of the additional cost of building an oversized powerplant and the cost of installing a battery (for every MWh of battery storage added, it would entail an additional capex of US\$0.3-0.6 million). Assessing these optimal power supply/electrolyser capacity mixes is essentially subjective to scope, location and available infrastructure and is beyond the scope of this study. Subsequent studies would have to be conducted to achieve this design optimisation. Nevertheless, the required functionalities for such optimisation are built into the accompanying tools to assess such studies.

Additionally, from a technology perspective, increasing the electrolyser efficiency will drive down the LCOH. At present, commercial electrolysers have an energy efficiency of ~65% on an LHV basis, but as suggested in [Report B](#), R&D and commercialisation of modern electrolysers that can operate at over 85% efficiency and be constructed at competitive costs is underway. Our estimates show that achieving such efficiencies would reduce the LCOH by 27%. Moreover, from a system perspective, water consumption will be a concern due to challenges in procuring high-purity water in the PICTs. However, our analysis shows that even at high water consumption rates and supply costs, the LCOH will increase by 2.5%. Therefore, water supply becomes a jurisdictional concern rather than an economic one.

### Pathway to Parity

Altogether, consensus suggests that for renewable H<sub>2</sub> to become competitive globally, the costs would have to reach close to US\$1–1.5/kg for viability across the different end-use sectors. [Figure 16D](#) provides a pathway towards achieving parity with these costs (under the baseline assumptions), as shown the electrolyser cost and energy prices in the order of US\$500/kW and US\$25/MWh (at a high-capacity factor as close to 100%) would be required to bridge the gap and bring the LCOH at US\$3/kg. Further reduction would then require lowering WACC, CAPEX offsets, efficiency improvements, and achieving economies of scale.

### Ammonia Production

The H<sub>2</sub> generated from electrolysers can then be converted to ammonia through the Haber Bosch process. The section below estimates the cost of conversion to ammonia. The ammonia facility assumed hydrogen supply from electrolysis coupled with the dedicated solar/wind farm; these were then integrated with the Haber Bosch (HB) reactor through an intermediate H<sub>2</sub> storage tank. An Air Separation Unit (ASU) was included for the required N<sub>2</sub> supply. The levelised cost of ammonia (LCOA) was estimated at different scales (1, 10, 500 ktpa, and 1 Mtpa) in the estimation of the hydrogen cost.

### Cost Assumptions

**Capital and Operating Costs of HB and ASU:** The capital costs for the HB reactor and ASU were adopted from the recent estimates by the IEA, which suggest a price of US\$770/tNH<sub>3</sub>/yr for the combined HB and ASU unit.<sup>1</sup> To account for the economies of scale, the scale index model was again adopted, with a scale index of 0.7.<sup>41</sup>

**Project Financing:** The capital costs were then assumed to be financed at a WACC of 10% over a 20-year project lifetime.

**Operation and Maintenance Costs:** 3% of CAPEX/year was assumed to account for the HBU's O&M costs.

**Ammonia Yield:** Generally, Haber Bosch units are rated and installed with a nameplate capacity that reflects the maximum capacity the facility can operate it. However, for an electrolysis-connected electrolyser, the hydrogen throughput to the system varies, and therefore, the HB units do not operate at a fixed capacity. To account for this, we assume a range of capacity factors (25% to 100%) to reflect the impact on the levelised costs.

**Hydrogen Costs:** To estimate the subsequent H<sub>2</sub> requirement, the stoichiometric requirement of 0.18 tonne of H<sub>2</sub> needed per tonne of NH<sub>3</sub> is considered, as highlighted in **Report B**. For the base case, an H<sub>2</sub> supply cost of US\$10/kg is considered based on the estimates in **Section 4.1**.

**Hydrogen Storage Costs:** Hydrogen storage was considered a buffer between the electrolyser and the HB unit. The storage capacity was then sized based on the maximum daily H<sub>2</sub> demand and cost, which was US\$600/kg.<sup>42</sup>

**Levelised Cost of Ammonia:** The levelised cost of ammonia (LCOA) was then estimated using a similar approach to that used for H<sub>2</sub>. **Table 7** summarises the parameters used for the analysis.

**Table 7.** Ammonia Production Costing Assumptions

Parameter	Value
<b>Ammonia Facility</b>	
Scale	10 ktpa, 100 ktpa, 500 ktpa and 1 Mtpa (Base Case 1 Mtpa)
Capital Cost of HB and ASU Unit	US\$770/tNH <sub>3</sub> /yr assumed at 1 Mtpa capacity
Operating Costs of HB and ASU Unit	3% of CAPEX/year
Capacity Factor	100%
<b>Hydrogen Facility</b>	
Hydrogen Requirement	0.18 tonne of H <sub>2</sub> /tonne of NH <sub>3</sub> (assuming 100% conversion)
Hydrogen Supply Cost	US\$10/kg
Hydrogen Storage Costs	US\$600/kg
<b>Financing</b>	
WACC	10%
Lifetime	20 years

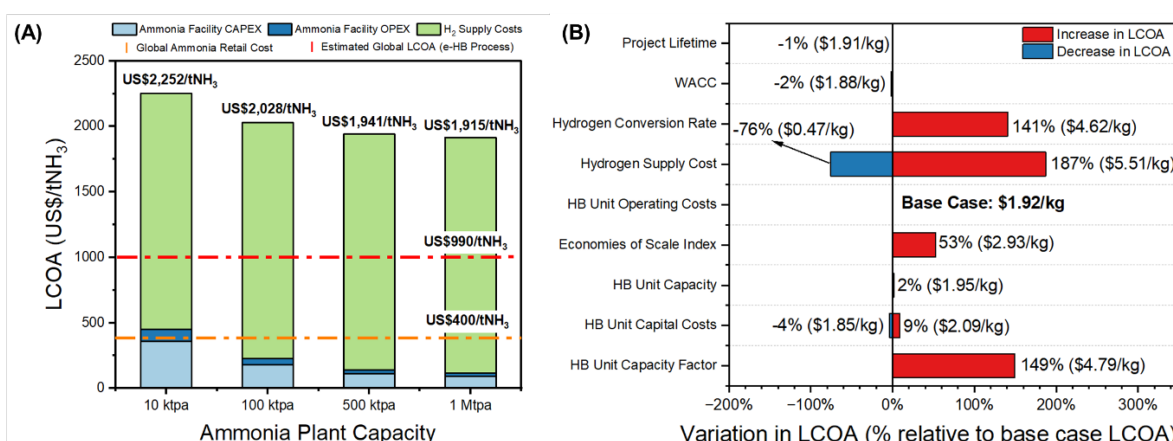
**Sensitivity Analysis:** A sensitivity analysis was conducted to evaluate the impact of significant cost drivers on the LCOA. The sensitivity analysis parameters shown are in **Table 8**.

**TABLE 8. ASSUMED SENSITIVITY ANALYSIS SCENARIOS FOR AMMONIA PRODUCTION COSTS**

Sensitivity Parameter	Reasoning	Sensitivity Analysis Scenarios				
		A	B	C	D	E
Ammonia Facility Capacity Factor	Reflect impact of the flexibility of the Haber Bosch Unit	100%	80%	60%	40%	
Ammonia Facility Capital Costs	Reflect on the impact of the cost of the facility	3 x less than base case	1.5 x less than base case	1.5 x more than base case	3x more than base case	
Ammonia Facility Capacity	Reflect impact of economies of scale	10 ktpa	100 ktpa	500 ktpa	1 Mtpa	
Economies of Scale Index		0.7	0.6	0.5		
Ammonia Facility Operating Costs	Reflect on the impact of the cost of the facility	5% of CAPEX/yr	4% of CAPEX/yr	3% of CAPEX/yr	2% of CAPEX/yr	1% of CAPEX/yr
H <sub>2</sub> Supply Costs	Reflect the impact of the cost of H <sub>2</sub> generation	US\$2/kg	US\$5/kg	US\$10/kg	US\$20/kg	US\$30/kg
Conversion Rate	Reflect the impact of constrained single-pass conversion across the reactor	100%	80%	60%	40%	
WACC	Reflect the impact of financing	9%	8%	7%	6%	5%
Project Lifetime		10 years	15 years	25 years	30 years	

### Levelised cost of Ammonia Estimates

**Figure 17** shows the outlook of the renewable ammonia production costs (LCOA). Overall, at a large scale 1 Mtpa ammonia capacity plants, the LCOA is estimated to range between US\$1.9/kg of NH<sub>3</sub>; this cost is significantly higher than the current global retail price of ammonia (> four times more than the US\$0.4/kg<sup>43</sup>) and the estimated cost of renewable ammonia production in major emerging markets (> two times higher than the US\$0.99/kg<sup>43</sup>).



**FIGURE 17. ESTIMATED COST OF RENEWABLE AMMONIA PRODUCTION IN PICTs.** HERE **(A)** REPRESENTS THE BREAKDOWN OF THE AMMONIA PRODUCTION COSTS AT DIFFERENT CAPACITIES OF THE HABER BOSCH UNIT AND COMPARES THEM TO THE PRESENT GLOBAL RETAIL COST OF AMMONIA AND THE GLOBAL ESTIMATED COST FOR RENEWABLE AMMONIA. AS OBSERVED AT PRESENT, WE ESTIMATE THAT EVEN FOR SUBSTANTIAL PRODUCTION CAPACITY (1 MTPA), THE LCOA WOULD BE 2 TO 4 TIMES HIGHER THAN THE REFERENCE GLOBAL RENEWABLE AMMONIA AND PRESENT RETAIL COST OF AMMONIA. **(B)** REPRESENTS THE LCOA

SENSITIVITIES. AS OBSERVED, THE LCOA IS MOST SENSITIVE TO H<sub>2</sub> SUPPLY COST, HB UNIT CAPACITY FACTOR AND H<sub>2</sub> CONVERSION RATE.

This high LCOA cost is driven by the high average production cost of H<sub>2</sub> in PICTs (estimated to be US\$10/kg, as seen in [Section 4.1](#)). The driving role of the hydrogen costs also dominates over the economies of scale, as observed scaling up from 10 ktpa to 1 Mtpa causes the impact of the capital and operating costs to decrease by up to 75%, which causes the LCOA to decrease but by a smaller factor (15%). This is again due to the driving nature of the H<sub>2</sub> supply costs in the overall LCOA mix, which scales up linearly with the increasing capacity of the Haber Bosch facility, offsetting the reduction in capital and operating costs.

### Sensitivity Analysis

Further insights on the critical drivers of LCOA are reflected through the sensitivity analysis (shown in [Figure 17B](#)). As noted, the LCOA is most sensitive to the cost of the hydrogen supply. If this cost of H<sub>2</sub> supply can be reduced to US\$2/kg, then this would significantly reduce the costs to US\$0.47/kg, within an acceptable range of the current retail price of ammonia (US\$0.4/kg). Inversely, if the cost of H<sub>2</sub> supply increases to US\$30/kg, which could be plausible in the high cost and low capacity factor scenarios, as highlighted in [Section 4.2](#), due to factors like the low renewable energy capacity factor and high installation/procurement cost of electrolyser deployment in the PICTs, therefore, the LCOA could increase to US\$5.5/kg, which would be 100 times more expensive than the current cost of ammonia generated globally. Nevertheless, with an ongoing decrease in electrolyser and renewable energy costs, optimisation of H<sub>2</sub> projects and maturing supply chains, the cost of H<sub>2</sub> will most likely decrease.

In addition to the cost of H<sub>2</sub>, the capacity factor is also an essential factor; inherently, the HB units are steady-state operation systems and thus like to be operated at higher capacity factors, which is an economic advantage as well. Nevertheless, coupling the HB reactor with an intermittent H<sub>2</sub> supply (through electrolysers operated with variable renewable energy sources) would mean frequent variation and disruptions in the H<sub>2</sub> supply. These can be managed by integrating intermediate H<sub>2</sub> storage. In contrast, from an LCOA perspective, the cost of storage will have little effect, but developing it is an additional upfront cost and a safety risk given the lack of gas-ready risk and infrastructure in the PICTs. The alternative approach is to oversize the electrolyser and renewable energy supply while supplementing with a battery; optimising these mixes will lower LCOA yet require an upfront increase in capital investment.<sup>44</sup> Moreover, recognising these challenges, HB reactor developers are commercialising flexible and dynamic HB reactors that can be operated at low loads and ramped up on demand.<sup>45</sup> Flexible operation of HB can then allow it to effectively absorb the intermittent H<sub>2</sub> supply, leading to lower LCOA.

Interestingly, the project financing (WACC and project life), capital and operating costs have a secondary role, as observed in [Figure 17B](#). This is primarily due to the cost of H<sub>2</sub> supply dominating the overall cost mix. As the cost of H<sub>2</sub> supply decreases to US\$4-6/kg, the impact of HB capital and operating costs become dominating factors in the LCOA mix. Altogether, the project financing, capital and operating costs will become a bridge towards economic viability at H<sub>2</sub> supply costs of US\$2/kg.

### Pathway to Parity

In summary, at present, the estimated cost of renewable NH<sub>3</sub> across the PICTs is up to four times higher than global retail prices. Yet, there is a pathway to achieving parity with



these costs, in the form of reduction of H<sub>2</sub> supply costs, which need to be reduced to US\$2/kg (achieving such hydrogen costs is possible in the medium term, as highlighted in [Section 4.2](#)). Yet alone, reducing the H<sub>2</sub> supply costs to US\$2/kg will reduce the LCOA to US\$0.47/kg, which is still 25% higher than the retail cost of ammonia. At this stage, optimising the HB/electrolyser facility to yield higher capacity factors, more favourable financing, and lower capital (CAPEX) and operating (OPEX) costs will be needed to bridge the remaining gap to the current market price.

## e-Methanol

The e-methanol production costs were estimated using renewable H<sub>2</sub> and CO<sub>2</sub> supply at different fuel production capacities of 1, 10, 100, and 500 tpd synthetic fuels.

### Cost Assumptions

**Capital Costs:** For the conversion costs, the capital cost of the methanol (MeOH) synthesis reactor was estimated based on literature sources (refer to the bio-methanol section below for details). These costs include the methanol synthesis reactor, knock-out pot, syngas multi-stage compressors and interstage coolers, and distillation system (also include installation cost, instrumentation and control cost, engineering contractor's fee, and contingency).<sup>46–48</sup> A reference cost of US\$6 million for one tpd of MeOH was established, with a scale factor of 0.5.

**Operation and Maintenance Costs:** An operating cost of 5% of the capital cost per year is considered.

**H<sub>2</sub> and CO<sub>2</sub> Source Costs:** For the e-pathways, we consider the H<sub>2</sub> supplied from electrolysis. For the base case, we assume the cost to be US\$10/kg (based on the above H<sub>2</sub> estimates), with a range of US\$2-20/kg. Similarly, we assume CO<sub>2</sub> costs an average of US\$50/tonne, with a range of US\$0 – US\$500/tonne of CO<sub>2</sub>.<sup>49</sup>

**Levelised Cost of Methanol:** By integrating these capital and operating costs, the levelised cost of methanol (LCOM) is estimated for the e-pathway using the same approach as [Equation 4](#). [Table 9](#) below summarises the assumptions used for evaluating the LCOM.

**Table 9.** e-Methanol Production Costing Assumptions

Parameter	Value
<b>Ammonia Facility</b>	
Scale	1, 10, 100 and 500 tpd (Base Case 100 tpd)
Capital Cost of MeOH Reactor	US\$6 million/tpd of MeOH assumed at 1 tpd capacity
Operating Costs of MeOH Reactor	5% of CAPEX/year
Capacity Factor	100%
<b>Hydrogen Facility</b>	
Hydrogen Requirement	0.18 tonne of H <sub>2</sub> /tonne of MeOH (assuming 100% conversion)
Hydrogen Supply Cost	US\$10/kg
Hydrogen Storage Costs	US\$600/kg
CO <sub>2</sub> Requirement	1.4 tonne of CO <sub>2</sub> /tonne of MeOH (assuming 100% conversion))
CO <sub>2</sub> Supply Cost	US\$50/tonne of CO <sub>2</sub>
<b>Financing</b>	
WACC	10%
Lifetime	30 years

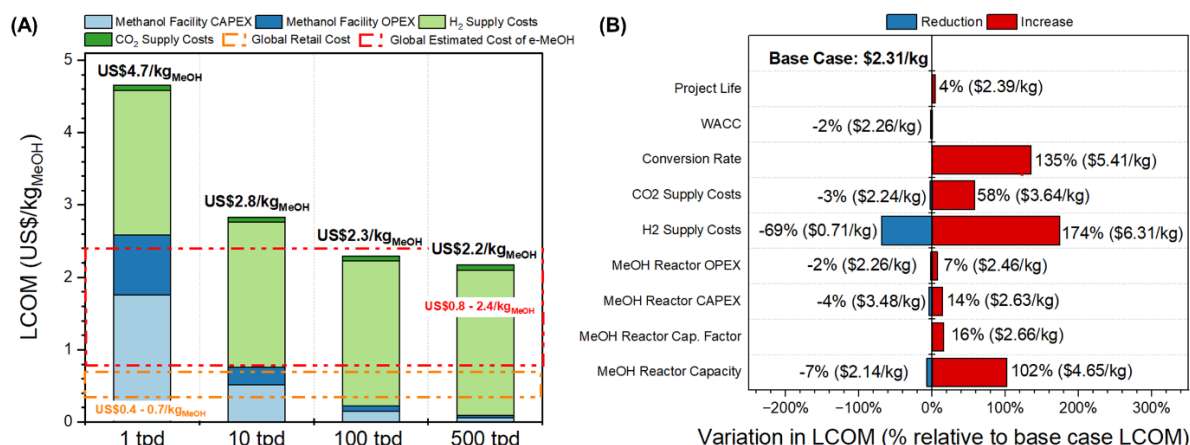
**Sensitivity Analysis:** In addition, sensitivity analysis was conducted to determine the key drivers of the LCOM costs. **Table 10** summarises the parameters used and the reasoning behind their selection.

**TABLE 10. ASSUMED SENSITIVITY ANALYSIS SCENARIOS FOR METHANOL PRODUCTION COSTS**

Sensitivity Parameter	Reasoning	Sensitivity Analysis Scenarios				
		A	B	C	D	E
Methanol Reactor Capacity	Reflect the impact of economies of scale	10 tpd	100 tpd	500 tpd	1,000 tpd	
Methanol Reactor Capacity Factor	Reflect the impact of the flexibility of the reactor	100%	80%	60%	40%	
Methanol Reactor Capital Costs	Reflect the impact of the cost of the reactor	3 x less than base case	1.5 x less than base case	1.5 x more than base case	3x more than base case	
Methanol Reactor Operating Costs	Reflect the impact of the cost of the reactor	15% of CAPEX/yr	10% of CAPEX/yr	5% of CAPEX/yr	2.5% of CAPEX/yr	1% of CAPEX/yr
H <sub>2</sub> Supply Costs	Reflect the impact of the cost of H <sub>2</sub> generation	US\$2/kg	US\$5/kg	US\$10/kg	US\$20/kg	US\$30/kg
CO <sub>2</sub> Supply Costs	Reflect the impact of the cost of CO <sub>2</sub> procurement	US\$0/ton	US\$50/ton	US\$100/ton	US\$500/ton	US\$1,000/ton
Conversion Rate	Reflect the impact of constrained single-pass conversion across the reactor	100%	80%	60%	40%	
WACC	Reflect the impact of financing	9%	8%	7%	6%	5%
Project Lifetime		10 years	15 years	25 years	30 years	

### Levelised Cost of e-Methanol Estimates

**Figure 18A** compares the estimated levelised cost of methanol production (LCOM) against the current retail cost of methanol (US\$0.4 – 0.7/kg<sub>MeOH</sub><sup>50</sup>), and IRENA estimated the global average cost of e-methanol (US\$0.8 – 2.4/kg<sub>MeOH</sub><sup>18</sup>). As observed, the estimated LCOM is likely to be significantly higher than the current retail cost of methanol (i.e. 3 to 10 times higher) but could match the e-methanol costs provided a high production rate is achieved (over 100 tpd). The key driver of the cost stack is the hydrogen supply costs (40% of the LCOM at 1 tpd and >90% at 500 tpd), whereas the impact of CO<sub>2</sub> supply costs is significantly less. This is so because, despite more significant amounts of CO<sub>2</sub> required (1.4 tCO<sub>2</sub>/t<sub>MeOH</sub>) compared to H<sub>2</sub> (0.2 tH<sub>2</sub>/t<sub>MeOH</sub>), the cost per unit of H<sub>2</sub> (US\$10/kg of H<sub>2</sub>) is significantly higher than the assumed cost of CO<sub>2</sub> (US\$50/ton or US\$0.05/kg of CO<sub>2</sub>). In addition, an increase in production capacity and the subsequent effect of economies of scale causes the LCOM to decrease. As observed, there was a 10-fold increase in capacity from 1 tpd to a reduction of 10 tpd in the LCOM by 40%. However, beyond 10 tpd, a doubling of capacity to 100 tpd only tends to decrease by ~20%, whereas a 100 tpd to 1,000 tpd decreases the LCOM by ~5%.



**FIGURE 18.** ESTIMATED COST OF E-METHANOL PRODUCTION IN PICTs. HERE (A) REPRESENTS THE BREAKDOWN OF METHANOL PRODUCTION COSTS AT DIFFERENT CAPACITIES OF METHANOL REACTORS AND COMPARES THEM TO THE PRESENT GLOBAL RETAIL COST OF METHANOL AND THE GLOBAL ESTIMATED COST OF RENEWABLE METHANOL. AS OBSERVED AT A LARGE-SCALE PRODUCTION CAPACITY OF 500 TPD, THE LCOM WOULD BE AT PAR WITH HIGH-END GLOBAL ESTIMATED RENEWABLE METHANOL COSTS AND ~2 TIMES HIGHER THAN THE PRESENT RETAIL COST OF METHANOL. (B) REPRESENTS THE LCOM SENSITIVES. AS OBSERVED, THE LCOM IS MOST SENSITIVE TO H<sub>2</sub> AND CO<sub>2</sub> SUPPLY COSTS, CONVERSION RATE AND METHANOL REACTOR CAPACITY.

### Sensitivity Analysis

**Figure 18B** then further breaks down the cost sensitivities across the driving parameters. As observed, the bulk of cost reductions compared to the base case cost of US\$2.3/kg at 100 tpd are driven by the decrease in H<sub>2</sub> price from US\$10/kg to US\$2/kg, which will reduce the cost LCOM by 70%. However, if the costs of H<sub>2</sub> supply increase to US\$30/kg, the LCOM will increase by 174% (US\$6.3/kg). From a CO<sub>2</sub> cost perspective, a US\$50/ton CO<sub>2</sub> supply cost is considered for the base case, which reflects the range of CO<sub>2</sub> capture from point sources such as bio gasification plants and industrial processes (such as cement plant or power generation units),<sup>49</sup> which would make e-methanol competitive with global estimates (provided a production capacity of over 100 tpd). Contrastingly, if Direct Air Capture (DAC) is used, this would increase the supply cost to over US\$100/ton to US\$300/ton, which would push up the LCOM by 14%. However, if the three times cost difference for projects developed in PICTs is considered, that could push the cost of CO<sub>2</sub> to nearly US\$1,000 per ton, which would result in the LCOM increasing by 26%.

The three-times difference in project costs in PICTs could also impact the capital and operating costs, which would result in an increase in production costs by 14% and 7%, respectively. This is due to the capital costs being annualised over a 30-year project life. If the project life is decreased to 10 years (under the assumed WACC of high WACC of 10%), it would further increase the LCOM by 4%.

The conversion rate will also affect performance; on a kinetic level, methanol synthesis generally has a single-pass conversion rate of 10% per pass.<sup>51</sup> The sensitivity analysis shows that at conversion rates  $\leq 40\%$ , the LCOM goes up to over US\$5/kg (135% increase over the base case). However, in practice, commercial methanol reactors are designed with recycle loops and optimised reactor configurations, including specialised catalysts that maintain a high conversion rate close to 100%.<sup>52,53</sup> Moreover, for methanol generation, a steady state supply of H<sub>2</sub> and CO<sub>2</sub> is required, requiring high-capacity operations and better economics. The sensitivity analysis shows that if the capacity factor goes down to 40%, which would be the case with unoptimised solar/wind profiles in the PICTs, the LCOM

will increase by 16%. Maintaining a high-capacity factor would then require optimising hydrogen production or developing buffer storage of CO<sub>2</sub> and H<sub>2</sub>.<sup>54</sup> While all these factors will impart additional costs, these would ultimately balance against the potential increase in LCOM that would otherwise be imparted due to the loss of capacity factor, as highlighted above.

### Pathway to Parity

Overall, under assumed assumptions, developing e-methanol facilities with capacities over 100 tpd would result in the LCOM matching global expectations. From a PICT's perspective, a few such large-scale facilities can be developed as centralised sources of methanol that can then be distributed for mobility or power generation applications.

Moreover, the secondary driver for economics is the hydrogen costs and its trade-off with the capital costs; if the capital costs are increased by a factor of 3 to reflect the higher capital case for developing projects in the PICTs, this would require H<sub>2</sub> costs below US\$8/kg, which is ambitious at this stage, as highlighted in [section 4.1](#) at present but achievable in the near term as the cost of electrolyzers and renewable energy decrease. However, this would require a low CO<sub>2</sub> cost of US\$50/tonne; if the costs increased to US\$500/tonne (within the cost range of DAC), this would require the hydrogen costs to be below US\$5/kg for the LCOM to match global expectations of (US\$2.4/kg<sub>MeOH</sub>).

In contrast, reaching parity with the present retail cost of methanol would be challenging without subsidies; our analysis shows a capital subsidy of 50% of the capital cost would be required for the LCOM to reach parity with US\$0.7/kg<sub>MeOH</sub> for H<sub>2</sub> costs below US\$2/kg (along with CO<sub>2</sub> cost at US\$50/tonne and capital cost being 3 times the base value). If the projects can be developed at the estimated capital costs (without the 3 times higher cost assumptions for the PICTs), parity with the US\$0.7/kg<sub>MeOH</sub> can be reached at US\$2/kg (and a CO<sub>2</sub> cost of US\$50/tonne).

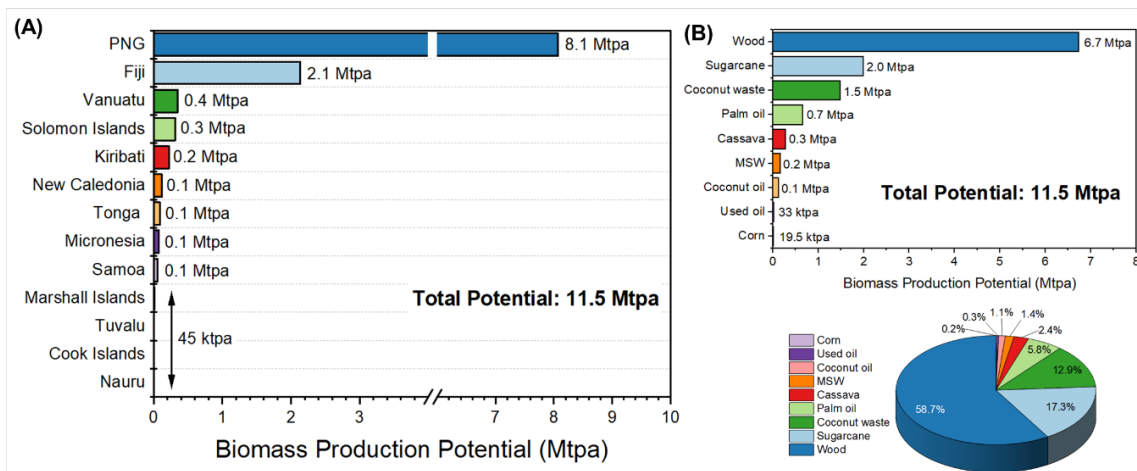
## 4.2. Bio-Fuel Production

Alternatively, biofuel variants of methanol (bio-methanol), as well as sustainable aviation fuel (SAF) and renewable diesel (RD), can be generated using biomass feedstocks. This usually occurs through biomass-to-liquid fuel conversion pathways such as gasification for bio-methanol production (biomass/waste gasification to syngas followed by the conversion of syngas to methanol), gasification coupled with Fischer Tropsch (GFT), hydrotreating of esters and fatty acids (HEFA) and the alcohol-to-jet (AtJ) conversion for SAF and RD production, respectively as highlighted in [Report B](#). Below the cost of generating bio-methanol, SAF and RD are estimated using these pathways.

### Biomass Availability

To model the production of biofuels, the biomass resources in PICTs are assessed, with a focus on biomass suitable for methanol, SAF, and renewable diesel production. Several biomass resources with high potential in PICTs and suitability for biofuel production include coconut oil, palm oil, used cooking/motor oil, corn, cassava, sugarcane, wood, coconut waste, and municipal solid waste.<sup>55-57</sup>

[Figure 19A](#) shows that wood, sugarcane, and coconut waste are the top three biomass resources by tonnage in PICTs. By country, biomass resources are concentrated in Papua New Guinea (PNG) and Fiji, amounting to nearly 90% of all resources ([Figure 19B](#)).



**FIGURE 19. REGIONAL DISTRIBUTION OF BIOMASS RESOURCES ACROSS THE PICTS. THIS BIOMASS POTENTIAL MAPPING (BY TONNAGE) IS BASED ON (A) REGIONAL AVAILABILITY AND (B) THE TYPE OF FEEDSTOCK. AS OBSERVED, PNG AND FIJI PRODUCE ~90% OF THE BIOMASS ACROSS THE PICTS, WHILE WOOD AND SUGARCANE (BAGASSE) ARE THE MORE READILY AVAILABLE BIOMASS RESOURCES.**

### Seasonal Variability in Biomass Supply

Several environmental and agricultural factors influence seasonal variability in biomass feedstock supply in PICTs.

#### Wood-based Feedstocks

Wood-based feedstocks are prevalent in the PICTs and are available all year round. However, the value of the wood feedstocks for biofuel production varies based on the type of wood species. The more native species such as *Casuarina* (Ironwood), *Cordia* (Kanawa) and *Callophyllum* (Tamanu) species that are widely distributed across the PICTs can be used as bio-feedstocks. However, they have a long growth cycle requiring upwards of 10 years or longer to reach maturity. Amongst the higher-value wood feedstocks are *Eucalyptus*, *Leucaena*, and *Albizia*; these trees are ideal for short-rotation biomass production and biofuel feedstock due to their rapid growth and high biomass yield. These species reach maturity in 5 - 10 (*eucalyptus*), 2 - 4 (*leucaena*) and 5 - 7 years (*albizia*). Other agroforestry species, such as *Gliricidia* and *Calliandra*, can be leveraged as they have a low time requirement to reach maturity and can be harvested every 2 - 5 years.

#### Agricultural Residues

Agricultural residues such as sugarcane bagasse, coconut husks, and cassava leaves/stalks and peels depend on agricultural cycles.

- **Bagasse:** Bagasse availability is directly tied to sugarcane production; therefore, supply is abundant post-harvest season. Based on the agricultural cycles of Fiji, the most significant producer of sugarcane in the region, there is a turnaround of 12 - 18 months between the planting to reach full maturity for harvesting. Sugarcane planting typically occurs during the wet season (November to April), whereas harvesting occurs primarily during the dry season (typically from May to November). Sugarcane is usually planted once every 5-7 years in the form of ratoon crops (regrowth from the same root system), with a new planting required after this cycle. In addition, bagasse availability is also dependent on the sugar market, with high demand and prices incentivising large-scale production and processing of sugarcane. Recently, the sugarcane industry has been facing numerous development challenges that extend beyond land and resource

management, illustrating the broader issues involved in increasing the resilience of agricultural systems. Therefore, bagasse supply might not be the most stable biomass feedstock available in the PICTs in the long run.

- **Coconut Waste:** In comparison, coconut production and supply are relatively more stable and reliable. Coconut trees tend to produce fruit continuously, with coconuts maturing at different times throughout the year. Coconuts can be harvested throughout the year; the coconut fruit reaches maturity at around 12 months. In comparison, a coconut tree can take 6-10 years, with trees typically producing 50-100 coconuts per year, depending on the age, for up to 80 years. Although harvesting occurs year-round, many PICTs experience peak harvesting periods during the dry season (May to October). The dry season is preferred because there is less rainfall, making the collection of coconuts easier, and the risk of spoilage during transport is lower.
- **Cassava:** Cassava is a resilient and drought-tolerant crop that thrives in tropical and subtropical climates, making it well-suited for many PICTs. While cassava is primarily cultivated for food, its biomass, particularly cassava stalks and peels, can also be used as feedstock for biofuel production. Cassava generally reaches full maturity within 8-18 months, depending on the variety, growing conditions, and local climate. Cassava can be grown and harvested year-round in some PICTs due to the tropical climate. However, many farmers prefer to plant and harvest according to seasonal rainfall patterns to maximise yield and reduce the risk of spoilage. Overall, on a crop basis, cassava is ready for harvest at around 12-14 months during the dry season (May to October).

## Oils

Regionally produced oils from palm or coconut, as well as waste oils from domestic applications, can be used for biofuel production.

- **Coconut Oil:** Coconut oil availability is also linked with coconut growth. There is Widespread cultivation across PICTs, with significant annual production, as highlighted above. Year-round production, with peak harvests from May to October. Mature trees continue to yield during the off-season (November to April). These can then be used for biodiesel production.
- **Palm Oil:** In comparison, palm oil is limited by the growth and availability of palm cultivation. At present, they are limited to certain regions, primarily Papua New Guinea and the Solomon Islands. Palm fruit also undergoes year-round production, with peak harvests in the dry season (May to October). Mature palms can produce fruit continuously.
- **Waste Oil:** PICTs with larger urban populations, such as Fiji (especially Suva), Papua New Guinea (Port Moresby), and Samoa (Apia), typically generate higher amounts of waste oil. However, comprehensive data on the exact quantities generated is limited. These oils include cooking oil from restaurants, hotels, and households, and oil used in vehicles and machinery also contributes to waste oil generation. This includes used lubricants from automotive maintenance and industrial machinery, particularly in sectors such as fisheries, agriculture, and construction.

## Municipal Solid Waste

Amongst the different of municipal solid wastes (MSW) available for biofuel production in the PICTs include:



- **Organic Waste:** Organic waste, such as food waste and scraps, can be used as gasification feedstocks. Similarly, wood waste, such as waste from construction, demolition, and urban green management, can provide wood waste in the form of timber offcuts, sawdust, and pruned branches. These are abundant and widely available in urban and rural areas of PICTs.
- **Paper Products:** Recycled wastepaper and cardboard can be used.
- **Plastic and Textile Waste:** Plastics, mainly low-density polyethylene (LDPE) and polyethylene terephthalate (PET), form a considerable portion of the MSW stream. Clothing and textile waste contribute to the MSW stream in many urban centres of the PICTs. Textile waste can be incinerated for energy production or, in advanced processes, converted into syngas or liquid biofuels.
- **Sewage and wastewater:** Sewage and wastewater in urban areas can be used as feedstocks for syngas generation (precursor for biofuel generation).

### Competing Uses for Biomass

However, it is essential to acknowledge the competition of biomass for other applications. In the region, wood and coconut waste are used as domestic fuels. Overall, MSW has the lowest competition; generally, organic waste predominates the MSW produced across the region (50 – 60% of all waste produced); this high proportion of organic waste in the MSW stream limits the need for separation, and organic content has a higher biofuel production potential. In comparison, wood and agricultural feedstocks would have to be managed both due to competition and land use. Coconuts (husks and oils), palms (husk and oil), and bagasse are the most valuable commodities in the region. Coconut and palm fruits are used to generate oil, copra, cream/milk, and drinking water as value-added opportunities in the area. In Fiji, for instance, Tropik Woods and Nabou Green are industrial users of coconut shells and husks. Bagasse is used for power generation; many sugar mills in PICTs use cogeneration systems to produce electricity and steam from bagasse. This process allows mills to become energy self-sufficient while providing excess electricity to local grids. It is also used for animal feed, organic fertiliser, and paper/packaging manufacturing.

Moreover, as a waste of the sugar industry, the nature of the sugar industry will impact supply. The sugarcane industry in Fiji faces numerous development challenges that extend beyond land and resource management, illustrating the broader issues involved in increasing the resilience of agricultural systems.<sup>xviii</sup> Similarly, wood has competing uses for power and heat generation, and the timber industry and native species are vital for the region's eco-stability. Agri-forests and fast-growing species such as eucalyptus can be planted and harvested for biofuel production, but this would depend on land availability.

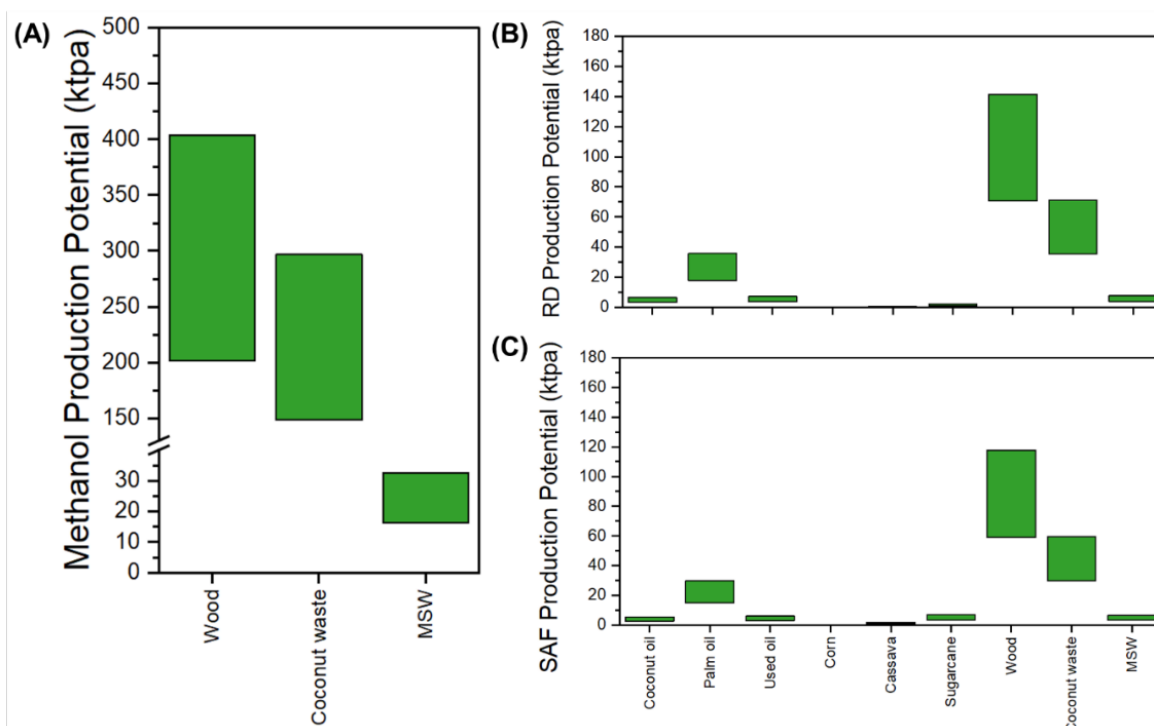
Overall, the biomass feedstocks are likely to peak during the summer season (alignment with the wood and Agri crop growth and harvesting cycles). Overall, MSW/waste oil offers a more stable supply of feedstocks. Yet, waste collection in the region is challenging due to a lack of infrastructure. In comparison, regulatory frameworks for the distribution and growth of biofuels on designated land would have to be introduced for wood and agri sources of feedstocks to ensure long-term sustainability. Moreover, to account for the seasonal variability, buffer storage capacity would have to be established to reduce risks of supply shortage and accommodate for the time lag in the sources reaching maturity.

<sup>xviii</sup> <https://www.frontiersin.org/journals/sustainable-food-systems/articles/10.3389/fsufs.2024.1358647/full>

## Estimated Production Potential of Biofuels Based on Feedstock Availability

**Figure 20** estimates the biofuel yields via HEFA, AtJ, and GFT based on the selectivity of the process, which has been calculated based on a literature study. Given that the critical constraint for biomass conversion is competing uses by other sectors, utilisation rates are assigned to each feedstock, reflecting the share of their total annual production being used for biofuel production. Feedstocks with higher constraints are assumed to have a 5 – 10% utilisation rate (e.g. corn, sugarcane, wood and other valuable feedstocks that already have an established market, such as palm oil and coconut oil), while feedstocks with lower constraints (e.g. waste oil, coconut waste and municipal solid waste - MSW) have a 20 – 40% utilisation rate.<sup>58</sup>

Feedstock	Bio-Methanol Potential		Bio-RD Potential		Bio-SAF Potential	
	Low (ktpa)	High (ktpa)	Low (ktpa)	High (ktpa)	Low (ktpa)	High (ktpa)
Coconut oil			3	7	3	5
Palm oil			18	36	15	30
Used oil			4	7	3	6
Corn			0	0	0	0
Cassava			0	1	1	2
Sugarcane			1	2	3	7
Wood	202	404	71	141	59	118
Coconut waste	148	297	36	71	30	59
MSW	16	32	4	8	3	6



**FIGURE 20. ESTIMATED PRODUCTION POTENTIAL FOR SYNTHETIC FUELS IN PICTs BASED ON REGIONAL BIOMASS RESOURCES. HERE, THE ESTIMATED PRODUCTION POTENTIALS ARE REPRESENTED BY (A) METHANOL, (B) SAF (SYNTHETIC AVIATION FUEL), AND (C) RD (RENEWABLE DIESEL) PRODUCTION. NOTE: THE PRODUCTION POTENTIAL IS BASED ON THE AVAILABILITY OF BIOMASS FEEDSTOCK (BASED ON OVERALL REGIONAL AVAILABILITY AND ASSIGNED UTILISATION RATE) AND THE YIELD OF THE PROCESS.**

The estimated methanol production potential from feedstocks suitable for gasification processes is presented in **Figure 20A**. As observed overall, woody biomass and coconut

waste offer a high production capacity potential of methanol. **Figure 20B-C** shows the estimated SAF and renewable diesel production potential from different feedstocks (under maximum jet mode for SAF and maximum diesel mode for renewable diesel) in the PICTs. Woody biomass and coconut waste processed via the GFT pathway present a high potential for both SAF and renewable diesel production. In addition, oil biomass, particularly palm oil, shows considerable potential despite its sustainability issue due to land utilisation and competing uses with the cooking oil industry. In this context, shifting to used cooking/motor oil feedstock is promising, although feedstock availability is relatively lower.

The production costs for each pathway using various feedstocks are estimated to provide insights into the technology's feasibility. In this instance, the effects of scale and several dynamic factors, such as feedstock cost, total fuel yield, capacity factor, CAPEX, discount rate, and plant lifetime, are investigated to understand the cost drivers. Then, cost-reduction mechanisms for each process are proposed.

## Bio-Methanol

Assessment of the methanol production costs was conducted at different fuel production capacities of 1, 10, 100, and 500 tpd synthetic fuels, using Papua New Guinea as a representative case study of the PICTs given its highest biomass potential. The bio methanol production considers the gasification of biomass feedstocks such as municipal solid waste (MWS), wood and coconut residue to generate syngas, which is further conditioned using steam methane reforming to achieve the desired feedstock ratio (C: H<sub>2</sub>) prior to passing through the methanol synthesis reactor.

## Cost Assumptions

**Capital Cost:** Capital costs include the purchase cost of central process units, installation costs, instrumentation and control costs, engineering contractor's fees, and contingency costs. The main process equipment costs for the purchase were sourced from existing literature.<sup>46-48</sup> The purchased equipment costs were scaled from the reference year to the year of analysis (2023) using the Chemical Engineering Plant Cost Index (CEPCI). In addition, to scale the purchased costs found in the literature to the capacities explored in this study, the economy of scale was considered using the scaling factors from the literature. **Equation 3** was used to calculate the adjusted process equipment CAPEX.

$$\text{Adjusted CAPEX} = \text{Reference CAPEX} \times \frac{\text{CEPCI 2023}}{\text{CEPCI reference year}} \times \left( \frac{\text{Base case capacity}}{\text{Reference capacity}} \right)^{\text{Scaling factor}} \quad (3)$$

The installed equipment costs are then obtained by multiplying the baseline equipment costs with the installation factor, specific to each type of equipment.<sup>46,47</sup> The instrumentation and control costs, engineering contractor's fees and contingency costs were estimated to be 47%, 36%, 22%, and 44% of the total purchased equipment costs.

**Operation and Maintenance Costs:** The operating costs considered the direct production costs (biomass feedstock, water, catalysts, chemicals, wastewater treatment, operating labour, and maintenance and repairs), fixed charges (insurance costs 0.5% of CAPEX and local taxes and fees 0.5% of CAPEX), plant overhead costs (50% of labour and maintenance costs), and general expenses (20% of labour and maintenance costs).

**Methanol Yield:** The methanol yields were adopted from literature estimates as summarised in **Table 11**. Wood, coconut waste, and MSW were considered feedstocks for the gasification process. Wood was considered the constraint feedstock due to competing markets like timber.

**TABLE 11. FEEDSTOCK CONVERSION AND UTILISATION SCENARIOS FOR BIO-METHANOL PRODUCTION VIA GASIFICATION PROCESS.**<sup>46,59,60</sup>

Feedstock	Methanol yield	Low feedstock use	High feedstock use
Wood	60%	5%	10%
Coconut waste	50%	20%	40%
MSW	50%	20%	40%

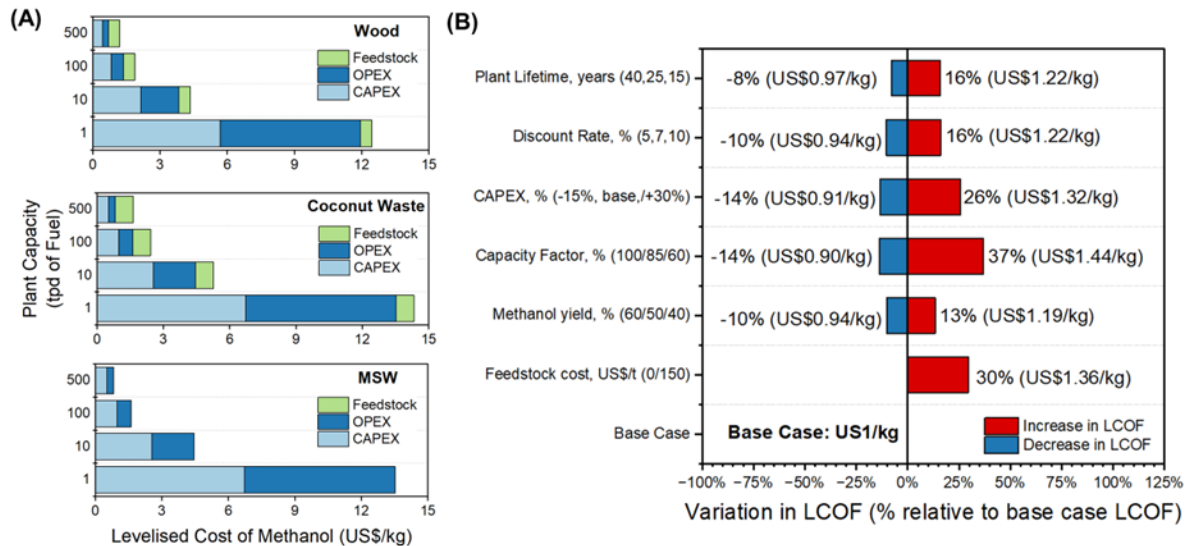
**Levelised Cost of Methanol:** Once the capital and operating costs are established, they are integrated to estimate the levelised cost of methanol (LCOM – US\$/kg) using a discounted cash flow method, as shown in **Equation 4**.

$$LCOM = \frac{\sum_{i=0}^n \frac{CAPEX_i + OPEX_i}{(1+r)^i}}{\sum_{i=1}^n \frac{P_{\text{methanol}}}{(1+r)^i}} \quad (4)$$

Here, CAPEX is the total capital costs, OPEX is the annual operating costs,  $r$  is the discount rate, and  $P_{\text{methanol}}$  is the annual methanol production.

### Estimated Levelised Cost of Bio-Methanol

The levelised cost of methanol from wood, coconut waste, and municipal solid waste was estimated at different capacities of 1, 10, 100, and 500 tpd fuels, as shown in **Figure 21A**. At the small scale of 1 tpd, the production costs are extremely high, above US\$9/kg. However, when the capacity is scaled to 100 tpd, they are significantly reduced to US\$0.83, US\$1.39, and US\$1.05/kg for wood, coconut waste, and municipal solid waste, respectively.



**FIGURE 21. ESTIMATED COST OF BIO METHANOL-PRODUCTION USING THE GASIFICATION PATHWAY. HERE (A) REPRESENTS THE LCOM BREAKDOWN ASSUMING FEEDSTOCKS SUCH AS WOOD, COCONUT WASTE, AND MUNICIPAL SOLID WASTE GASIFICATION AT DIFFERENT METHANOL REACTOR CAPACITIES. (B) REPRESENTS THE COST SENSITIVES FOR METHANOL PRODUCTION VIA WASTE GASIFICATION AT A CAPACITY OF 100 TPD FUELS.**

These results strongly indicate that economies of scale are critical in the gasification process to lower both CAPEX and OPEX. It is apparent that at a lower scale, the cost becomes very sensitive to the plant size. However, as the scale increases, the cost of production becomes less sensitive to the plant size. Finding the optimum scale to reach the economy of scale is essential in biomass gasification, as biomass logistics may be

constrained due to geographical dispersion. As illustrated in **Figure 21A**, the minimum scale of the gasification plant should be targeted to ensure economic competitiveness is around 100 tpd of methanol production. Nevertheless, compared to current fossil methanol prices (US\$0.3/kg), these costs are still higher, with municipal solid waste presenting the most promising feedstock to be economically viable due to its lower feedstock cost. However, challenges are presently associated with the gasification efficiency of processing municipal solid waste and the impact of contaminants, which may alter the actual capital and operational costs.

**Sensitivity Analysis:** A cost sensitivity analysis was carried out to determine the cost drivers that may lead to cost reduction for the gasification process (**Figure 21B**). The base case scenario is based on the gasification process for municipal solid waste at a production capacity of 100 tpd synthetic fuels. Feedstock cost is the most affecting factor. In the base case, municipal solid waste costs US\$0/ton, and the estimated cost is US\$1.05/kg. Nevertheless, with significant competing uses of municipal solid waste feedstock for waste-to-energy applications, this cost is likely to increase in the future. An increase to US\$150/ton<sup>47</sup> leads to a significantly higher levelised cost of methanol, around US\$1.36/kg. The second cost-determining factor is the total fuel yield. Improving efficiency from 50% to 60% can cut down costs by around 10%.

### Pathway to Parity

In summary, at present, the estimated cost of bio-methanol is higher than global retail prices (US\$0.4 – 0.7/kg<sub>MeOH</sub><sup>50</sup>). Yet, there is a pathway to achieving parity with these costs, such as through CAPEX reduction and efficiency improvements. For example, a 30% reduction in total CAPEX combined with an increase in fuel yield to 60% is expected to lower the methanol production cost by approximately 25% from the base case scenario. The challenge, however, to realise this cost reduction is the consistency of feedstock quantity and quality, as these factors may affect the operational capacity factor, fuel yield, and CAPEX required for the gas cleaning process. In addition, when MSW is used as the feedstock, there is an opportunity to offset the production cost through additional revenues, waste tipping fees, and carbon credits. In PNG, a tipping fee of around US\$4 per ton MSW is charged at Baruni dumpsite in Port Moresby.<sup>61</sup> Regarding carbon credits, this will depend on the overall life-cycle emissions, which require further assessment and the development of carbon markets. In PICTs, the voluntary carbon markets are currently small and nascent but are expected to grow.<sup>62</sup>

### Bio-SAF and Renewable diesel

Assessment of the SAF and renewable diesel production costs was conducted at different fuel production capacities of 1, 10, 100, and 500 tpd synthetic fuels, using Papua New Guinea as a representative case study of the PICTs given its highest biomass potential.

### Cost Assumptions

**Capital Costs:** Capital costs include the purchase cost of central process units, installation costs, instrumentation and control costs, engineering contractor's fees, and contingency costs. The main costs of the purchased process equipment were sourced from existing literature for HEFA, AtJ, and GFT.<sup>46</sup> The purchased equipment costs were scaled from the reference year to the year of analysis (2023) using the Chemical Engineering Plant Cost Index (CEPCI). In addition, to scale the purchased costs found in the literature to the capacities explored in this study, the economy of scale was considered using the scaling factors from the literature (through **Equation 3**)

The installed equipment costs are then obtained by multiplying the equipment costs with the installation factor specific to each type of equipment. The instrumentation and control costs, engineering contractor's fees, and contingency costs were estimated to be 47%, 36%, 22%, and 44% of the total purchased equipment costs, respectively.

**Operation and Maintenance Costs:** The operating costs considered the direct production costs (biomass feedstock, water, catalysts, chemicals, wastewater treatment, operating labour, and maintenance and repairs), fixed charges (insurance costs 0.5% of CAPEX and local taxes and fees 0.5% of CAPEX), plant overhead costs (50% of labour and maintenance costs), and general expenses (20% of labour and maintenance costs).

**SAF/RD Yield:** The SAF/RD yields were also adopted from literature estimates as summarised in **Table 12**. Note herein that in addition to the utilisation factor, selectivity is considered, which reflects the conversion to the targeted fuel. Herein, the chosen pathway is based on the most suitable process for the feedstock to obtain the highest yield. To represent this, the max jet mode refers to the operational mode optimised for SAF production. In contrast, the max diesel mode refers to the operational mode optimised for renewable diesel production.

**TABLE 12. FEEDSTOCK CONVERSION AND UTILISATION SCENARIOS FOR SAF/RD PRODUCTION.**

Feedstock	Pathway	Total fuel yield	SAF selectivity (max jet)	Diesel selectivity (max diesel)	Low feedstock use	High feedstock use
Coconut oil	HEFA	90%	50%	60%	5%	10%
Palm oil	HEFA	90%	50%	60%	5%	10%
Used oil	HEFA	90%	50%	60%	20%	40%
Corn	AtJ	20%	70%	20%	5%	10%
Cassava	AtJ	10%	70%	20%	5%	10%
Sugarcane	AtJ	5%	70%	20%	5%	10%
Wood	GFT	20%	50%	60%	5%	10%
Coconut waste	GFT	20%	50%	60%	20%	40%
MSW	GFT	20%	50%	60%	20%	40%

**Levelised Cost of Synthetic Fuels:** Once the capital and operating costs are established, they are integrated to estimate the levelised cost of synthetic fuels (LCOF – US\$/kg) using a discounted cash flow method, as shown in **Equation 4**. It is important to note that the processes will produce a mix of fuel fractions based on selectivity; therefore, for simplicity, the LCOF is calculated for all liquid fuel fractions, including gasoline, jet fuel, and diesel fuel, assuming those fractions are sold at the same price. The LCOF were then benchmarked against the current cost of Diesel (US\$1.3/kg.<sup>63</sup>) and Aviation Fuel (US\$0.7/kg <sup>64</sup>) in Fiji as a reference for the PICTs.

### Costing based on the Hydrotreated Esters and Fatty Acids (HEFA) process

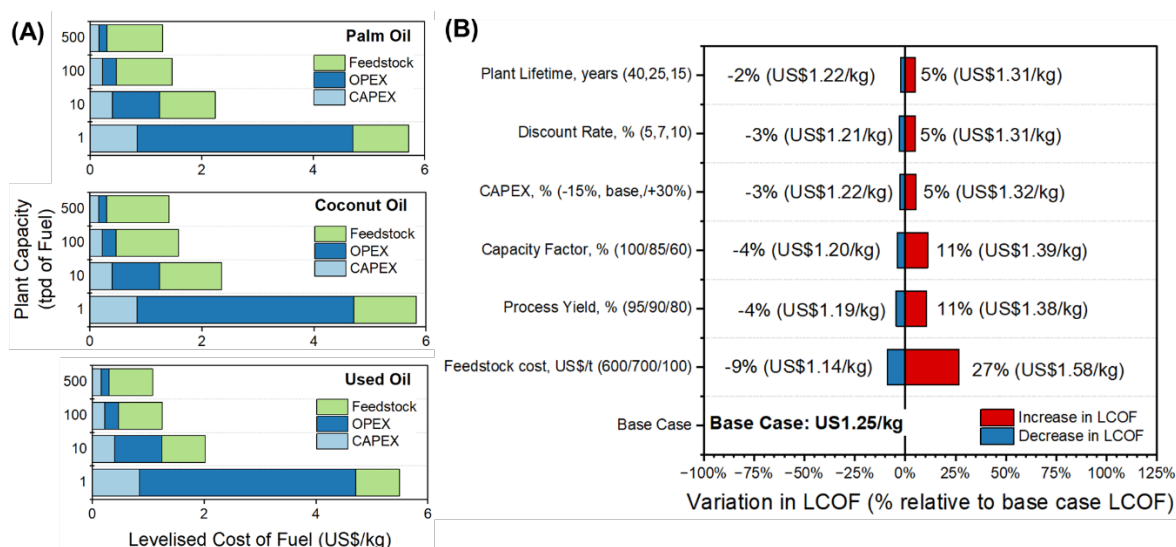
HEFA uses oil biomass as feedstock for SAF/RD production. Palm oil, coconut oil, and used oil are primary oil biomass available in considerable quantities in PICTs, predominantly in PNG.

**LCOF Estimates:** At the small scale of 1 tpd, the production costs are extremely high, above US\$5/kg, and are significantly reduced to US\$1.47, US\$1.41, and US\$1.25/kg for palm oil, coconut oil, and used oil, respectively, when the capacity is 100 tpd. These results strongly indicate that economies of scale are critical in the HEFA process to lower both



CAPEX and OPEX, particularly labour costs. It is apparent that at a lower scale, the cost becomes very sensitive to the plant size. However, as the scale increases, the price becomes less sensitive to the plant size. Finding the optimum scale to reach an economy of scale is essential in all bio pathways, including HEFA, as biomass logistics may be constrained due to geographical dispersion.

**Figure 22** shows the estimated levelised cost of HEFA fuels from palm oil, coconut oil, and used oil at different capacities of 1, 10, 100, and 500 tpd. As illustrated in **Figure 22A**, the minimum scale of the HEFA plant should be targeted to ensure economic competitiveness of around 100 tpd of synthetic fuel production. Nevertheless, compared to current fossil jet fuel prices, these costs are still higher, with used oil presenting the most promising feedstock to be economically viable.



**FIGURE 22. ESTIMATED COST OF SYNTHETIC FUEL PRODUCTION USING THE HEFA PATHWAY. HERE, (A) REPRESENTS THE LEVELISED COST BREAKDOWN OF THE HEFA PATHWAY (ASSUMING DIFFERENT BIOMASS FEEDSTOCKS) AT DIFFERENT PLANT CAPACITIES. (B) REPRESENTS THE COST SENSITIVITY ANALYSIS FOR THE HEFA PATHWAY AT A CAPACITY OF 100 TPD FUELS.**

**Sensitivity Analysis:** The cost sensitivity analysis, a powerful tool for understanding the potential cost variations, was conducted to identify the factors that could lead to cost reduction (**Figure 22B**). The base case scenario, which is based on the HEFA process for used cooking oil at a production capacity of 100 tpd synthetic fuels, reveals that feedstock cost is the most significant factor. In this scenario, the oil cost was US\$700/ton, and the estimated cost was US\$1.25/kg. However, with the potential for significant competing uses of oil feedstock for other bioenergy applications, this cost may increase in the future. A potential increase to US\$1,000/ton results in a significantly higher levelised cost of synthetic fuels, around US\$1.58/kg. The second critical cost-determining factor is the capacity factor, which is directly linked to feedstock availability. A decrease in the capacity factor to 60% leads to an increase in the production cost to US\$1.39/kg. Lastly, there is room for cost improvement from fuel yield enhancement. A 5% increase in efficiency, from 90% to 95%, can lead to a 5% reduction in costs, highlighting the potential for cost savings through process optimisation.

### Pathway to Parity for HEFA

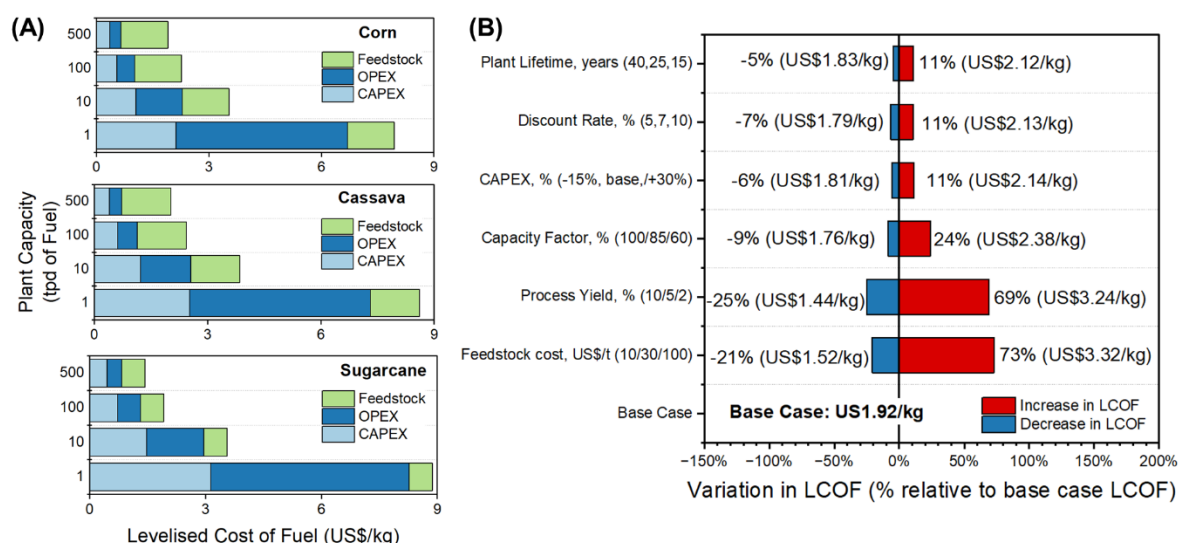
In summary, at present, the estimated cost of HEFA-derived synthetic fuels is slightly higher than global retail prices. Yet, there is a potential pathway to achieving parity with

these costs, such as through CAPEX reduction and efficiency improvements. For example, a 30% reduction in total CAPEX combined with an increase in process efficiency to 95% is expected to lower the production cost by approximately 10% from the base case scenario. More importantly, it is imperative to ensure that biomass feedstock can be sourced at a sufficiently affordable price, though HEFA feedstock costs have been quite volatile in recent years.<sup>65</sup> In addition, there is an opportunity to offset the production cost further through carbon credits. This will depend on the overall life-cycle emissions, which require further assessment and the development of carbon markets. In PICTs, the voluntary carbon markets are currently small and nascent but are expected to grow.<sup>62</sup>

### Costing based on the Alcohol to Jet (AtJ) Pathway

AtJ uses biomass alcohols, such as bioethanol, as feedstock for SAF. Various lignocellulosic biomasses can be used to produce bioethanol. In PICTs, some promising lignocellulosic biomass for the AtJ process include corn, cassava, and sugarcane.

**LCOF Estimate:** The levelised cost of AtJ fuels was estimated using corn, cassava, and sugarcane as feedstocks at different capacities of 1, 10, 100, and 500 tpd fuels (**Figure 23A**). At a small scale of 1 tpd, the production costs are extremely high, above US\$5/kg and are significantly reduced to US\$2.27, US\$2.44, and US\$1.92/kg for corn, cassava, and sugarcane, respectively, when the capacity is 100 tpd. These results strongly indicate that economies of scale are critical in the AtJ process to lower both CAPEX and OPEX, particularly labour costs. It is apparent that at a lower scale, the cost becomes very sensitive to the plant size. However, as the scale increases, the price becomes less sensitive to the plant size.



**FIGURE 23.** ESTIMATED COST OF SYNTHETIC FUEL PRODUCTION USING THE ATJ PATHWAY. HERE, (A) REPRESENTS THE LEVELISED COST BREAKDOWN OF SYNTHETIC FUELS FOR THE ATJ PATHWAY (ASSUMING DIFFERENT BIOMASS FEEDSTOCKS) AT DIFFERENT PLANT CAPACITIES. (B) REPRESENTS THE COST SENSITIVITY ANALYSIS FOR THE ATJ PATHWAY AT A CAPACITY OF 100 TPD FUELS.

**Sensitivity Analysis:** Moreover, a cost sensitivity analysis was carried out to determine the cost drivers that may lead to cost reduction (**Figure 23B**). The base case scenario is based on the AtJ process for sugarcane at a production capacity of 100 tpd synthetic fuels. Feedstock cost is the most affecting factor. In the base case, sugarcane costs US\$30/ton, and the estimated cost is US\$1.92/kg. Nevertheless, with significant competing uses of oil feedstock for other bioenergy applications, this cost may increase in the future. An

increase to US\$100/ton<sup>66</sup> leads to a significantly higher levelised cost of synthetic fuels, around US\$3.32/kg. The second cost-determining factor is the total fuel yield. Improving efficiency from 5% to 10% can cut down costs by up to 25%.

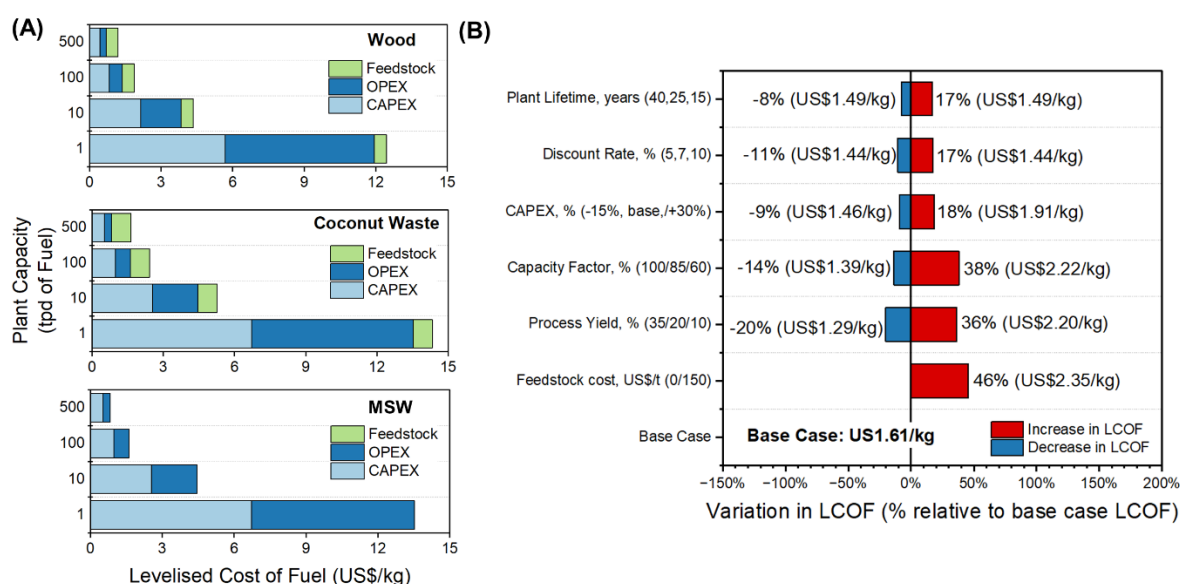
### Pathway to Parity for AtJ

In summary, at present, the estimated cost of AtJ-derived synthetic fuels is higher than global retail prices. Yet, there is a potential pathway to achieving parity with these costs, such as through CAPEX reduction and efficiency improvements. For example, a 30% reduction in total CAPEX combined with an increase in fuel yield to 10% is expected to lower the production cost by approximately 40% from the base case scenario. More importantly, it is imperative to ensure that the biomass feedstock can be sourced at a sufficiently affordable cost, noting that the sensitivity analysis pinpoints feedstock cost as the primary cost driver in AtJ. In addition, there is an opportunity to offset production costs further through carbon credits, as highlighted earlier; this will depend on the overall life-cycle emissions, which require further assessment and the development of carbon markets.

### Costing based on the Gasification and Fischer-Tropsch (GFT) Process

GFT uses lignocellulosic biomass (e.g., woody biomass and coconut waste) and municipal solid waste as feedstock for synthetic fuels.

**LCOF Estimate:** Figure 24 shows the estimated levelised cost of GFT fuels from wood, coconut waste, and municipal solid waste at different capacities of 1, 10, 100, and 500 tpd of fuels. At the small scale of 1 tpd, the production costs are extremely high, above US\$10/kg and are significantly reduced to US\$1.87, US\$2.42, and US\$1.61/kg for wood, coconut waste, and municipal solid waste, respectively, when the capacity is 100 tpd.



**FIGURE 24. ESTIMATED COST FOR SYNTHETIC FUEL PRODUCTION USING THE GFT PATHWAY. HERE, (A) REPRESENTS THE LEVELISED COST OF SYNTHETIC FUELS FOR THE GFT PATHWAY (ASSUMING DIFFERENT BIOMASS FEEDSTOCKS AT DIFFERENT PLANT CAPACITIES. (B) REPRESENTS THE COST SENSITIVITY ANALYSIS FOR THE GFT PATHWAY AT A CAPACITY OF 100 TPD FUELS.**

These results strongly indicate that economies of scale are critical in the GFT process to lower both CAPEX and OPEX, particularly labour costs. It is apparent that at a lower scale, the cost becomes very sensitive to the plant size. However, as the scale increases, the

production cost becomes less sensitive to the plant size. Finding the optimum scale to reach economy of scale is essential in all bio pathways, including GFT, as biomass logistics may be constrained due to geographical dispersion. As illustrated in **Figure 24A**, the minimum scale of the GFT plant should be targeted to ensure economic competitiveness, which should be around 100 tpd of synthetic fuel production. Nevertheless, compared to current fossil jet fuel prices, these costs are still higher, with municipal solid waste presenting the most promising feedstock to be economically viable due to its lower feedstock cost. However, challenges are present associated with the gasification efficiency of processing municipal solid waste and the impact of contaminants.

**Sensitivity Analysis:** A cost sensitivity analysis was carried out to determine the cost drivers that may lead to cost reduction, and it was also conducted for the GFT process (**Figure 24B**). The base case scenario is based on the GFT process for municipal solid waste at a production capacity of 100 tpd synthetic fuels. Feedstock cost is the most affecting factor. In the base case, municipal solid waste costs US\$0/ton, and the estimated cost is US\$1.61/kg. Nevertheless, with significant competing uses of municipal solid waste feedstock for waste-to-energy applications, this cost is likely to increase in the future. An increase to US\$150/ton<sup>47</sup> leads to a significantly higher levelised cost of synthetic fuels, around US\$2.35/kg. The second cost-determining factor is the total fuel yield. Improving efficiency from 20% to 35% can cut down costs by around 20%.

### Pathway to Parity for GFT

In summary, at present, the estimated cost of GFT-derived synthetic fuels is higher than global retail prices. Yet, there is a pathway to achieving parity with these costs, such as through CAPEX reduction and efficiency improvements. For example, a 30% reduction in total CAPEX combined with an increase in fuel yield to 35% is expected to lower the production cost by approximately 25%. The challenge, however, to realise this cost reduction is the consistency of feedstock quantity and quality, as these factors may affect the operational capacity factor, fuel yield, and CAPEX required for the gas cleaning process. In addition, when MSW is used as the feedstock, there is an opportunity to offset the production cost through additional revenues, waste tipping fees, and carbon credits, as highlighted earlier.

**TABLE 13.** ESTIMATED COST OF BIOFUEL PRODUCTION AND COMPARISON AGAINST THEIR FOSSIL FUEL VARIANTS.

Production Pathway	Estimated LCOF (US\$/kg)		Comparison to Fossil Fuel Derivative Costs			
	1 tpd	500 tpd	Diesel		Aviation Fuel	
			Unit Price (US\$/kg)	LCOM rel. to Unit Price	Unit Price (US\$/kg)	LCOM rel. to Unit Price
HEFA	5.8	1.1	1.1 <sup>xix</sup>	0.8 – 4.5	0.7 <sup>xx</sup>	1.4 – 8.3
GFT	14	1.6		1.2 – 10.8		2.3 – 20
ATJ	8.5	1.5		1.15 – 6.5		2.1 – 12.1

**Table 13** provides a comparison between the estimated production cost of the biofuel variants (SAF and RD) and the current retail cost of the fossil fuel variants (conventional diesel and aviation fuel). As observed, small-scale facilities will struggle to compete and be viable against traditional fuels as the marginal cost for the shift could be up to 20 times

<sup>xix</sup> Cost of Jet Fuel in Fiji: <https://jet-a1-fuel.com/price/fiji>

<sup>xx</sup> Diesel Price in Fiji: [https://www.globalpetrolprices.com/Fiji/diesel\\_prices/](https://www.globalpetrolprices.com/Fiji/diesel_prices/)

higher. However, as the capacity increases to 500 tpd, the costs will start becoming competitive as the marginal cost for the shift will fall close to within two times the present costs.

Further reduction in costs would have then to be driven by CAPEX reduction, with expectations that the CAPEX of these pathways would decrease by up to 30% by 2050, which would lead the overall production costs at scale to fall to US\$1/kg. Similarly, the OPEX reductions would have to be realised, a key variable for which is the cost of fuel. This would depend on the conversion pathway and feedstock used. HEFA process utilises oil feedstocks (such as Palm and Coconut Oil), and as illustrated in **Figure 22B**, feedstock costs of <US\$700/tonne would cause the LCOF to decrease. For feedstock, costs of <US\$600/tonne would decrease the LCOF by 10%.

Similarly, for the AtJ process, which utilises agricultural biomass feedstocks such as Corn, Cassava and Sugarcane, feedstock costs below US\$30/tonne would result in cost reduction by up to 20%, as illustrated in **Figure 23B**. Meanwhile, the GFT process, which is based on wood, coconut, and plastic waste, would be heavily influenced by feedstock costs. It is assumed that these waste streams can be sourced for free; however, an increase in the cost of biomass collection, potentially up to US\$150/tonne, would lead to the LCOF increasing by 146% (as shown in **Figure 24B**).

Additionally, the conversion pathways would dictate yield and conversion efficiencies. Overall, the HEFA process has the highest maturity and yield (over 80%) and, therefore, can be used to produce SAF and renewable diesel cost-effectively in the short term. In comparison, the AtJ is currently limited in terms of conversion efficiency (10% yields). Yet, the process can be a promising pathway, especially if there are existing large-scale bioethanol production facilities where a fraction of the bioethanol capacity can be diverted into the AtJ production facility, allowing the process to capitalise on existing bioethanol infrastructure and potentially reducing upfront CAPEX. Bioethanol could also be used for direct blending with gasoline fuel for engines. In comparison, GFT is more efficient (up to 35% yields) and relies on waste streams, offering an attractive route to handle complex solid waste biomass feedstock, such as plant residues, forestry residues, mixed plastic waste, and municipal solid waste.

Altogether, theoretically, biofuel production offers an attractive opportunity that, through further CAPEX reduction and optimisation of a ubiquitous feedstock supply, would only become more economical. This is a well-recognised opportunity in the region, with biomass repeatedly identified as a key future energy source for the region. However, in practice, despite the region working on expanding the reliance on fossil fuels for decades, practical challenges such as seasonal variability of bioresources (mainly seasonal crops), competing uses, reliable collection and separation of feedstocks, particularly waste streams, at low costs, are significant constraints that would have to be overcome.

### 4.3. Import Based Supply

Alternatively, to local production, importing these H<sub>2</sub> and derivatives from emerging regional markets such as Australia and Indonesia could potentially be an option. These countries have an emerging portfolio of H<sub>2</sub> and derivatives production facilities and ambitions to become exporting countries and create green fuel corridors for global trade.

#### Australia

Australia is a potential hub for renewable H<sub>2</sub> and derivative production (ammonia and methanol), with one of the largest pipelines of projects and a national target to become a globally competitive exporter. As of 2023, the country has a total of 106 active, planned and operational projects with a value of US\$160 – 210 billion. A vast majority of these are tailored towards hydrogen and derivative export, particularly in the form of methanol and ammonia. To support these, the Australian federal and state governments have put in place significant investments, grants and subsidies to make their production cost competitive. Studies have already highlighted that hydrogen and derivative exports from Australia would be competitive with other global markets.<sup>67,68</sup> An overview of the projects currently being developed and proposed suggests that export-oriented projects could become operational by the latter half of this decade (post-2028).<sup>69</sup> Recent cost studies have indicated that H<sub>2</sub>, ammonia and methanol can be generated in Australia at the cost of US\$4-6/kg, US\$0.7 – 1/kg and US\$0.8 – 2.3/kg (without any subsidies included).<sup>70</sup>

In addition, while the biofuel industry in Australia is in its infancy, the Australian government is also pursuing a SAF mandate. This includes the recent budget introduction of subsidies and incentives to develop regional SAF production hubs.<sup>71</sup> This is in line with the interests of major regional flight operators, including the national air carrier Qantas, which is setting targets for SAF offtake.<sup>72</sup> Australia’s national science agency, CSIRO, has released a sustainable aviation fuel roadmap that highlights the region’s potential to become a SAF production hub.<sup>58</sup> Their estimate suggests Australia can leverage its bioresources to potentially produce up to 6 GL/yr (~5 Mtpa) of SAF by 2030, which could lead to 12 GL/yr (~10 Mtpa) by 2050. The cost of producing this SAF would range between US\$1.3 – 2.6/kg.

## Indonesia

Indonesia is also a potential market for biofuel. The state already has over 12 GL/yr of biodiesel production capacity in place. While most of it is being used to fulfil local blending mandates (35 – 50% blending), 0.6 GL/yr of biodiesel is being exported from the region to markets in the EU and Asia. The cost of RD exports out of Indonesia in 2023 was estimated to average US\$930/tonne (US\$0.9/kg).

## United States of America

The USA is also emerging as a critical potential hub for H<sub>2</sub> and derivatives production in the Pacific region. The country is one of the largest producers and consumers of H<sub>2</sub>, ammonia, methanol and RD. However, most of this market is currently serviced through fossil fuel-based production. The US has adopted a robust incentive-led policy for green H<sub>2</sub> production, with cost cuts of US\$3/kg put in place for exclusively renewable-led production of H<sub>2</sub> and derivatives. Nevertheless, it is most likely, given the extent of the internal demand for H<sub>2</sub> and derivatives, that the upcoming potential output in the near to medium term would focus on decarbonising the existing value chain. However, in the long run, exports from the US could service the Polynesian PICTs (Hawaii, Samoa and Cook Island) due to their more excellent proximity to the Australian and Indonesian markets.

**TABLE 14. POTENTIAL OUTLOOK OF H<sub>2</sub> AND DERIVATIVES IMPORT FROM POTENTIAL EXPORT MARKETS TO THE PICTS**

Fuel			Landed Cost in PICTs (US\$/kg) <sup>xxi</sup>
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<sup>xxi</sup> These landed costs include the production cost of the fuel, on loading/offloading from the ship, as well as cost of shipment (cost of ship, its operation, labour charges, port charges and insurance costs). The production costs were adopted from prior industrial/academic studies, whereas the shipping costs were evaluated using the HySupply Shipping Tool that has been developed by UNSW Sydney as an open-source resource for costing shipments of green fuels.



	Exporting Country	Export Timeline	Production Cost	Shipping Cost	Total Import Cost
Hydrogen	Australia	Post-2028	Low: US\$4/kg High: US\$6/kg	US\$8	Low: US\$12/kg High: US\$14/kg
Ammonia			Low: US\$0.7/kg High: US\$1/kg	US\$0.1/kg (US\$100/t)	Low: US\$0.8/kg High: US\$1.1/kg
Methanol			Low: US\$0.8/kg High: US\$2.3/kg	US\$0.08/kg (US\$80/t)	Low: US\$0.9/kg High: US\$2.4/kg
SAF		Post 2030	Low: US\$1.3/kg High: US\$2.6/kg	US\$0.08/kg (US\$75/t)	Low: US\$1.4/kg High: US\$2.7/kg
RD	Indonesia	Ongoing	US\$1/kg	US\$0.1/kg	US\$1.1/kg

Using these locations as potential case studies, the landed cost of H<sub>2</sub> and derivatives in PICTs was estimated. **Table 14** provides the outlook of potential export timelines and their landed costs in Pacific markets from Australia and Indonesia as a reference. Overall, in the long run, importing H<sub>2</sub> and derivatives instead of fossil fuels does not enhance PICT's energy security situation. However, it could facilitate a transitional pathway as the region can initially rely on imported fuels to establish its value chain and demonstrate demand while scaling its production capacity.

#### 4.4. Summary

**Table 15** provides a comparison of the estimated cost of H<sub>2</sub> and derivative production in PICTs against their present fossil fuel counterparts and the globally estimated cost, including potential imports from regional markets. The following cost benchmarks for viability were established:

**Hydrogen:** Presently, the cost of hydrogen within the region would likely be significantly higher than global benchmarks. Yet, local production is still more competitive than importing hydrogen (significantly, as pure liquid hydrogen imports alone would cost an estimated US\$8/kg). The bulk of the cost reductions are estimated in **Section 4.1**, while essentially delivered off the back of a decrease in technology costs, globally, it is anticipated that as the hydrogen market scales, the cost of electrolyzers will fall, with expectations that the costs would fall to US\$500/kW by 2030. Moreover, electricity prices are a key driver, as energy prices at US\$25/MWh are needed for H<sub>2</sub> production to become competitive. For reference, the current electricity tariff in Fiji is 34 Fijian cents/kWh (based on their utility provider Energy Fiji Limited), which translates to US\$150/MWh. While these costs are for a fossil fuel-dominated grid, based on the IRENA specified cost for developing solar/wind farms, the estimated cost of newly built solar and wind in Fiji would be US\$70/MWh and US\$140/MWh, respectively.<sup>xxii</sup> This is a significant cost reduction challenge that, in the absence of subsidies or capital/energy cost support, will likely persist post-2030.

**Ammonia:** As highlighted in **Section 4.2**, for local ammonia production to become competitive, a low-cost H<sub>2</sub> supply of < US\$2/kg, Haber Bosch unit capacity of >100 ktpa with a high conversion rate and capacity factor would need to be developed. Altogether, H<sub>2</sub> supply costs are the key driver. Therefore, the long-term competitiveness of ammonia production will depend on the movements in the H<sub>2</sub> price. Moreover, even if local demand

<sup>xxii</sup> Considering the IRENA specified cost assumptions: Solar PV farm CAPEX of US\$880/kW and US\$7.5/kW/year, and Wind farm CAPEX of US\$1,280/kW and US\$50/kW/year, solar and wind capacity factors of 23% and 32% respectively in Fiji and WACC of 10% over 20 years.

is to be fulfilled by imports of green ammonia, they will likely be in the latter half of the decade when local production could become competitive based on H<sub>2</sub> cost expectations.

**Methanol:** Similarly, for the e-methanol pathway, the economics will essentially again be dictated by H<sub>2</sub> costs, with benchmarks such as a hydrogen supply cost of US\$5 – 8/kg, CO<sub>2</sub> supply costs within US\$50 – 500/tonne along with production capacities of >100 tpd with high conversion and capacity factors needed for local production to be competitive. While these costs are achievable, they are implausible in the near term. In comparison, bio-pathways are likely to be more competitive (both locally and through imports), but this would depend on developing high-capacity production units (>10 tpd), capital and operating cost support and establishing a reliable and low-cost biomass supply.

**SAF and Renewable Diesel:** The same applies to SAF and renewable diesel generated through bio-pathways.

Altogether, the timeline for these pathways to become cost-competitive depends on reaching the established cost benchmarks. These timelines are elaborated below.

**E-fuel:** For the e-pathways, given that the cost of renewables and electrolysis will dictate the cost of hydrogen production, the e—e-pathways are likely to incur a premium (in the absence of any cost support and incentives) up until 2040 onwards, where the price of H<sub>2</sub> production inherently falls to US\$2/kg. In the near term (up until 2030), we anticipate the price to be >US\$10/kg in the PICTs, with costs falling to US\$4 – 6/kg post 2030 before reaching US\$2/kg in the long run. The high cost of H<sub>2</sub> in the short term will impact the e-ammonia and e-methanol production costs, with these essentially becoming at par with fossil fuel alternatives once the expenses of H<sub>2</sub> fall to US\$2/kg (Post 2040). Inherently, given the better solar/wind resources in New Caledonia, it is likely to be the most competitive of the PICTs for e-fuel production, followed by Fiji, Vanuatu and PNG.

**Bio-fuels:** The cost of biofuels is likely to be higher than that of fossil fuel counterparts, but with a scale-up of production and establishment of stable feedstocks, the costs will become a part of fossil fuels mainly by 2030. Given that these technologies are already highly mature, we do not expect much variation in prices in the future. A key differentiator between regions would be a low-cost and sustainable feedstock supply; as such, PNG and Fiji could emerge as the key production hubs, given access to large amounts of feedstocks that can be leveraged at lower prices (wood, coconut waste and bagasse).

**TABLE 15.** ESTIMATED PRODUCTION COST OF H<sub>2</sub> AND DERIVATIVES IN THE PICTS.

Fuel	Estimated Cost (US\$/kg)	Cost Benchmark (US\$/kg)			Pathway to Parity	Cost Timeline
		Fossil Fuel Alternative <sup>xxiii</sup>	e/biofuel Comparison <sup>xxiv</sup>	Imported e/biofuel <sup>xxv</sup>		
Hydrogen	5 - 19	1 - 7 <sup>xxvi</sup>	2 - 12 <sup>Error! Bookmark not defined.</sup>	12 - 14	<ul style="list-style-type: none"> <li>Reducing the cost of financing (WACC reduction from 10% to 5%).</li> <li>Electrolysers scales of &gt;25 MW</li> <li>Electrolyser capital cost reduction to US\$500/kW.</li> <li>Renewable electricity price of ≤US\$25/MWh (for over 70% capacity factors)</li> </ul>	<ul style="list-style-type: none"> <li>Upto 2030: &gt;US\$10/kg</li> <li>2030 to 2040: US\$4-6/kg</li> <li>2040 onwards: &lt;US2/kg</li> </ul>
Ammonia	0.5 - 5.5	0.4 <sup>xxvii</sup>	1.0 <sup>xix</sup>	0.8 - 1.1	<ul style="list-style-type: none"> <li>Low cost H<sub>2</sub> supply (US\$2/kg)</li> <li>Haber Bosch unit capacity of &gt;100 ktpa</li> <li>High conversion rate and capacity factor</li> </ul>	<ul style="list-style-type: none"> <li>Upto 2030: &gt;US\$10/kg</li> <li>2030 to 2040: US\$4-6/kg</li> <li>2040 onwards: &lt;US2/k</li> </ul>
e-MeOH	0.7 - 6.3	0.4 - 0.7 <sup>xxviii</sup>	0.8 - 2.4 <sup>xxix</sup>	0.9 - 2.4	<ul style="list-style-type: none"> <li>H<sub>2</sub> supply cost below US\$8/kg for CO<sub>2</sub> supply cost of US\$50/tonne</li> <li>H<sub>2</sub> supply cost below US\$5/kg for CO<sub>2</sub> supply cost of US\$500/tonne</li> <li>Methanol reactor capacity of &gt;100 tpd</li> <li>High conversion rate and capacity factor</li> </ul>	<ul style="list-style-type: none"> <li>Upto 2030: &gt;US\$10/kg</li> <li>2030 to 2040: US\$4-6/kg</li> <li>2040 onwards: &lt;US2/kg</li> </ul>
bio-MeOH	0.9 - 1.4		0.3 - 1.0 <sup>Error! Bookmark not defined.</sup>		<ul style="list-style-type: none"> <li>High-capacity production units (&gt;10 tpd)</li> <li>Capital and operating cost reduction (interventions like subsidy or carbon credit)</li> </ul>	<ul style="list-style-type: none"> <li>Already cost competitive, with a low likelihood for further cost reduction</li> </ul>
SAF	1.1 - 14	0.7 <sup>xxx</sup>	2.3 <sup>xxxi</sup>	1.4 - 2.7	<ul style="list-style-type: none"> <li>Low-cost biomass feedstock</li> </ul>	
RD		1.1 <sup>xxxii</sup>	1.4 <sup>xxxiii</sup>	1.1		

<sup>xxiii</sup> These reflect the current retail cost of fossil fuel variants.

<sup>xxiv</sup> These reflect the estimated costs for bio/e-variants adopted from literature as a comparison.

<sup>xxv</sup> These reflect the cost of importing H<sub>2</sub> and derivatives from regional markets in Southeast Asia and Pacific. The production costs for the H<sub>2</sub> and derivatives were adopted from literature references, whereas the cost of shipping was evaluated using the HySupply Shipping Analysis tool, refer to [section 4.3](#) of the report for more details.

<sup>xxvi</sup> Adopted from IEA Global Hydrogen Review 2023. <https://www.iea.org/reports/global-hydrogen-review-2023>

<sup>xxvii</sup> Adopted from S&P Global Estimates. <https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/energy-transition/051023-interactive-ammonia-price-chart-natural-gas-feedstock-europe-usgc-black-sea>

<sup>xxviii</sup> Current Retail cost of Methanol. <https://www.methanex.com/about-methanol/pricing/>

<sup>xxix</sup> Adopted from IRENA Renewable Methanol Innovation Outlook.

[https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/Jan/IRENA\\_Innovation\\_Renewable\\_Methanol\\_2021.pdf](https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/Jan/IRENA_Innovation_Renewable_Methanol_2021.pdf)

<sup>xxx</sup> Cost of Jet Fuel in Fiji: <https://jet-a1-fuel.com/price/fiji>

<sup>xxxi</sup> Cost adopted from International Air Transport Association estimates. <https://www.iata.org/en/iata-repository/pressroom/fact-sheets/fact-sheet---fuel/>

<sup>xxxii</sup> Diesel Price in Fiji: [https://www.globalpetrolprices.com/Fiji/diesel\\_prices/](https://www.globalpetrolprices.com/Fiji/diesel_prices/)

<sup>xxxiii</sup> Based on renewable diesel production costs in US (Largest global producer of renewable diesel). <https://afdc.energy.gov/fuels/prices.html>. Cost of B100 - 100% renewable diesel was adopted.

## 5. End-Use Modelling

This section extends the production modelling to cost the established end-use cases. This involves building upon the H<sub>2</sub> and derivative supply costs as fuel costs and integrating the capital and operating costs of the end-use equipment to estimate the unit cost of operating the new technologies.

### 5.1. Scope

The economics of the following opportunities for H<sub>2</sub> and derivatives were evaluated for the PICTs:

- **On-Demand Power Generation:** The cost of electricity (\$/kWh) generated using H<sub>2</sub> fuel cells and renewable diesel-powered generators was estimated. This case considers that the H<sub>2</sub> and renewable diesel are generated in large-scale regional hubs and distributed across major and small islands (especially in remote off-grid locations).
- **Land Transport:** The total cost of ownership (\$/km) of operating land vehicles was evaluated for renewable diesel-operated and H<sub>2</sub> fuel cell vehicles (FCEVs).
- **Maritime Transport:** The shipping costs (\$/t.km) of operating ships using renewable diesel, methanol and ammonia were evaluated.
- **Aviation Transport:** The per unit seat cost (\$/seat.km) of operating different aircraft using SAF blends was evaluated.

### 5.2. Methodology

Herein, to assess the viability of deploying H<sub>2</sub> derivatives, opportunities were evaluated based on the marginal cost of fuel shift. This marginal cost of fuel shift was assessed by estimating the cost of an H<sub>2</sub>/derivative-based end-use solution against the cost of an equivalent incumbent fossil fuel-based system. For example, for assessing the cost of demand power generation, the levelised cost of electricity produced using a fuel cell was compared to a fossil diesel-operated generator. The difference in the power generation costs is the marginal cost. From this perspective, having a negative or zero marginal cost reflects a potentially viable opportunity to replace the incumbent fossil fuel-based opportunity with an H<sub>2</sub> and derivative solution.

**Note:** Herein, we exclusively compare the economics of H<sub>2</sub> and derivative against incumbent fossil fuel solutions. Yet, as highlighted across the series of reports, there will be competition against direct electrification, especially for power generation and land transport. The direct comparison against electrification is beyond the scope of this study and would have to be evaluated on a case-to-case basis. Accompanying tools for assessing this H<sub>2</sub> and derivatives end-use opportunities across the Pacific have been developed and will be made available through the project website to assist with further analysis.

Nevertheless, literature analysis in **Report B** revealed that solar/wind coupled systems with battery power could be competitive for small-duration operations (6 to 8 hrs of backup power). Similarly, for low-duty and range operations, electric vehicles will be more competitive than fuel cells. Analysis from IRENA, as *highlighted later in this section*, suggests that direct electrification is likely to be complemented with H<sub>2</sub> and derivatives to develop the most cost-optimum 100% renewable energy system

### 5.3. On-Demand Power Generation

In this section, the electricity generation costs using an H<sub>2</sub> fuel cell system and renewable diesel generators are estimated. The capacity of a 1 MW system is assumed as it can be suitable for small-scale demand (residential areas, offices, hospitals or resorts) and an off-grid community. Different operating scenarios, including continuous power supply (24/7) and intermittent operation of 2,4,8,12 and 20 hours a day, are costed.

#### Levelised Cost of Electricity

Based on these assumptions, the levelised cost of electricity production (LCOE – US\$/kWh) and the marginal cost of fuel switch (LCOE – US\$/kWh) were estimated, as shown:

$$\text{LCOE} \left( \frac{\text{US\$}}{\text{kWh}} \right) = \frac{\text{CRF} \times \text{CAPEX (US\$)} + \text{OPEX} \left( \frac{\text{US\$}}{\text{yr}} \right)}{\text{Electricity Produced (kWh)}} \quad \text{Cost of Fuel Switch} \left( \frac{\text{US\$}}{\text{kWh}} \right) = \text{LCOE}_{\text{Diesel}} - \text{LCOE}_{\text{H}_2/\text{Derivative}}$$

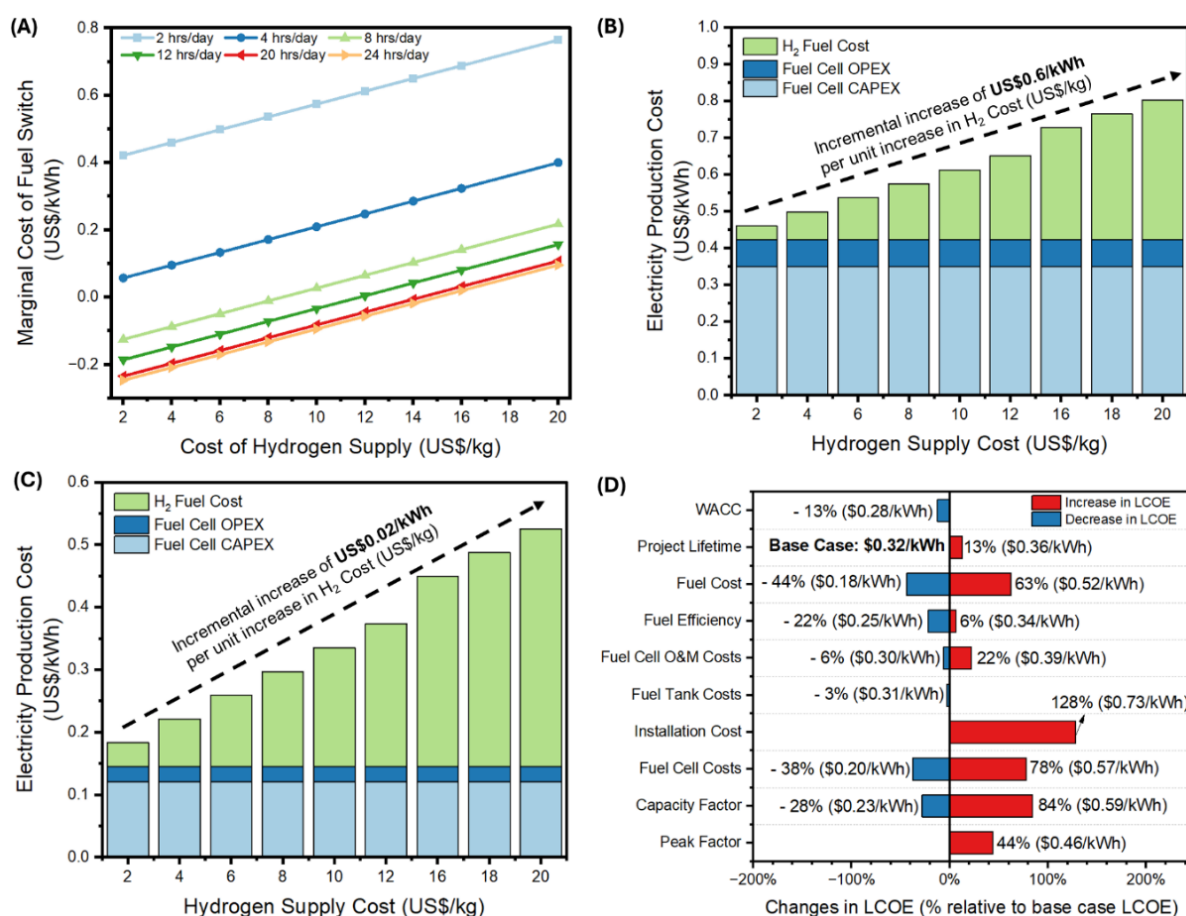
#### H<sub>2</sub> Fuel Cell vs Diesel Generators

Below, the marginal cost of replacing diesel generators with an H<sub>2</sub> fuel cell is estimated. **Table 16** lists the parameters adopted to calculate the electricity costs of fuel cells, which are compared against the costs of an equivalent diesel generator. **Note:** A sensitivity analysis is conducted to highlight a pathway for cost parity further; the sensitivity parameters are reflected in the brackets in the table.

**TABLE 16.** OPERATIONAL PARAMETERS AND EXPENSES OF DIESEL AND FUEL CELL GENSETS.

Parameter	Unit	Diesel Genset	Fuel Cell
Genset size	MW	1	1
Peak factor	%	100%	100% (50 – 100%)
Capacity Factor	Hrs/day	12 hrs	12 hrs (4 – 24 hrs)
	Days/year	300 (300 – 365)	300 (300 – 365)
Plant lifetime	years	20	20 (10 – 20)
Genset purchase cost	US\$/kW	520 <sup>73</sup>	3,500 <sup>74</sup> (500 – 10,000)
Genset installation cost	Times of Purchase Cost	0	0 (1 – 3)
Genset O&M costs	US\$/kWh	0.02 <sup>75</sup>	2.5% of CAPEX/year (1 – 10%/year)
Fuel tank purchase cost	US\$/L or US\$/kg	15 <sup>73</sup>	80 (50 – 100) <sup>76,77</sup>
Fuel Consumption	L/kWh or kg H <sub>2</sub> /MWh	0.32 <sup>78</sup>	19 (12.5 – 22)
	Efficiency - HHV (%)	30%	75% <sup>74</sup> (50% – 90%)
Fuel Costs	\$/L or \$/kgH <sub>2</sub>	1.1 <sup>63</sup> (0.5 – 2)	9 (2 – 20)
WACC	%	5%	10% (5% – 10%)
CRF	%	8%	11.7% (8% – 11.7%)

**Figure 25** provides an outlook on the estimated cost of electricity produced using fuel cells.



**FIGURE 25. ECONOMICS OF H<sub>2</sub> USE FOR POWER GENERATION USING FUEL CELLS IN PICTS.** HERE **(A)** REPRESENTS THE MARGINAL COST OF FUEL SHIFT FROM DIESEL GENSETS TO HYDROGEN FUEL CELLS AS A FUNCTION OF DIFFERENT HYDROGEN SUPPLY COSTS AND BACKUP POWER REQUIREMENTS FOR VARIOUS OPERATIONAL HOURS PER DAY. AS OBSERVED FOR PARITY WITH DIESEL-BASED POWER GENERATION, AN H<sub>2</sub> SUPPLY COST OF <US\$10/KG FOR AT LEAST 8 HRS OF CUMULATIVE ON-DEMAND POWER WOULD BE REQUIRED. ADDITIONALLY, THE ESTIMATED ELECTRICITY PRODUCTION COST BREAKDOWN USING H<sub>2</sub> FUEL CELLS IS PROVIDED FOR **(B)** 4 HRS AND **(C)** 12 HRS OF CUMULATIVE ON-DEMAND POWER GENERATION. AS OBSERVED, FOR HIGHER CUMULATIVE HOURS OF POWER GENERATED, THE INCREMENTAL INCREASE IN ELECTRICITY PRICE IS LOWER THAN THAT FOR LOWER PRODUCTION HOURS PER DAY. **(D)** REPRESENTS THE SENSITIVITY ANALYSIS OF ELECTRICITY PRODUCTION COSTS USING H<sub>2</sub> FUEL CELLS. AS OBSERVED, THE ELECTRICITY PRODUCTION COSTS ARE MOST SENSITIVE TO THE COST OF FUEL CELL AND ITS INSTALLATION, H<sub>2</sub> FUEL COST, FUEL CELL CAPACITY AND PEAK POWER FACTOR.

**LCOE Estimates:** Firstly, these estimates (**Figure 25A**) show that the costs are sensitive to two significant factors, namely the hydrogen fuel supply costs (US\$/kg) and the duration of operation (hrs/day). Secondly, it can be determined that for a viable switch, the fuel cells would have to be operated at over 8 hrs/day at a hydrogen fuel cost of <US\$12/kg. As highlighted earlier in **Section 4**, hydrogen production costs in the order of US\$10/kg are possible, with room for US\$2/kg to cover the cost of distribution and storage. H<sub>2</sub> can be transported to sites as compressed gas using tube trailers, as highlighted in **Report B**. The cost of compressing H<sub>2</sub> is estimated to add US\$1-2/kg to the production costs.<sup>79</sup> IRENA estimates that transporting compressed H<sub>2</sub> using tube trailers (1- 10 tpd over a distance of 100 km) would cost between US\$0.5 – 0.75/kg.<sup>80</sup> Altogether,



this would result in hydrogen supply costs of US\$11 – 13/kg of H<sub>2</sub>, which would be competitive with the US\$12/kg benchmark needed for parity.

**LCOE Breakdown:** This aspect is illustrated further in **Figure 25B-C**, which breaks down the estimated LCOE across the significant contributing factors, with the cost of fuel revealed as the primary driver. Moreover, it is observed that increasing tradeoff and increasing the hours of operation lowers the influence of the capital and operating costs of the fuel cell with the increased electricity produced. As such, relying on fuel cells is then driven by the hydrogen costs, and a viable switch can occur at a hydrogen cost of US\$12/kg.

**Sensitivity Analysis:** **Figure 25D** provides a sensitivity analysis of the LCOE, which reveals that higher capital and installation costs and capacity/peak factors will impact the LCOE the most. Both the peak factor and capacity factor directly affect the electricity yield; therefore, from an economic perspective, they need to be kept as high as possible, i.e., a peak factor of as close to 100% and a capacity factor of >50%. Additionally, the capital costs need to be managed as this will decrease the margin of H<sub>2</sub> fuel costs, which will result in an economical fuel switch. If the capital costs are a factor of 1.5 times the base case, this would require the H<sub>2</sub> fuel costs to be <US2/kg for an economical fuel switch based on the current diesel price. If the capital costs are three times the base case, this would require the diesel fuel costs to be ~US1.8/litre (double the current costs) at the present estimated hydrogen production costs of US\$10/kg.

## Renewable Diesel in Generators

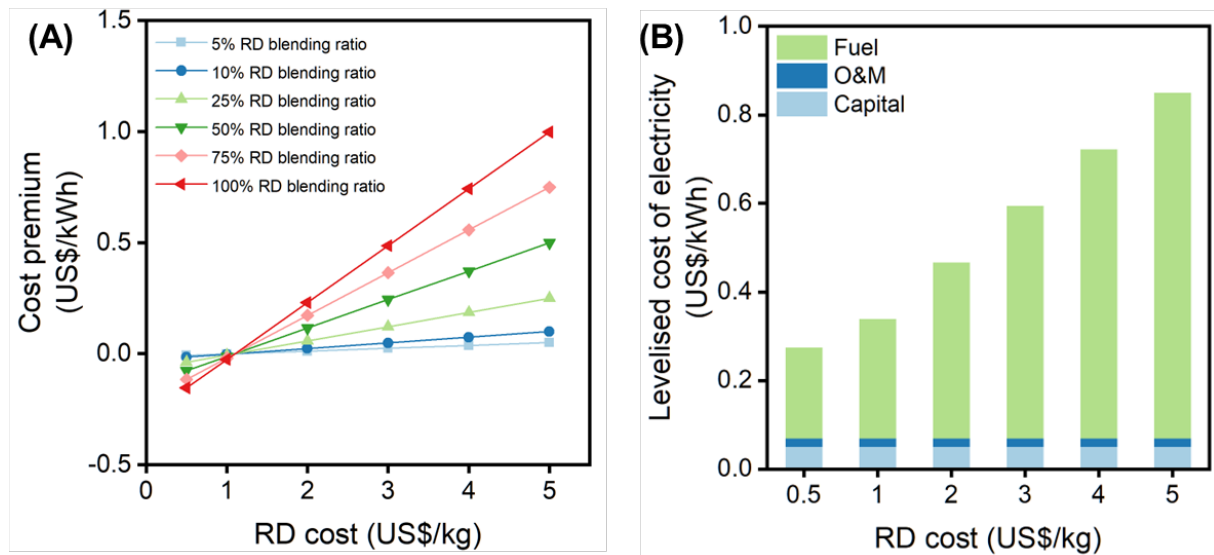
Renewable diesel end-use application as a drop-in fuel replacement for power generation is modelled based on a local small-scale power plant case. The capacity studied here is 100 kW, which can be utilised to power small residential areas, offices, and buildings. The operational parameters and expenses of the diesel power plant are summarised in **Table 17**.

**TABLE 17. OPERATIONAL PARAMETERS AND EXPENSES OF THE DIESEL POWER PLANT.**

Parameter	Unit	Diesel power plant
Genset size	kW	100
Capacity factor	%	100
Plant lifetime	years	25
Annual outage	days	30
Genset purchase cost	US\$/kW	270 <sup>73</sup>
Balance of plant	US\$/kW	250 <sup>73</sup>
Genset installation cost	% of CAPEX	40
Fuel tank purchase cost	US\$/L	15 <sup>73</sup>
Fuel tank installation cost	US\$/L	2
O&M	US\$/kWh	0.02 <sup>75</sup>
Fuel	L/kWh	0.32 <sup>78</sup>
	\$/kg	1.1 (fossil diesel) <sup>63</sup>
Discount rate	%	7

### LCOE Estimation:

The levelised cost of electricity (LCOE) is calculated to evaluate the impact of renewable diesel cost on the economics of diesel power generation system. At the current fossil diesel price of US\$1.1/kg, the LCOE is estimated to be US\$0.35/kWh for a 100-kW power plant. A sensitivity analysis is then carried out to evaluate the cost premium for shifting to renewable diesel under different renewable diesel costs and blending ratios (**Figure 26A**). The LCOE breakdowns under different renewable diesel costs at 50% blending ratio are shown in **Figure 26B**.



**FIGURE 26.** ECONOMICS OF RENEWABLE DIESEL USE FOR POWER GENERATION IN PICTs. HERE, **(A)** REPRESENTS THE COST PREMIUM (MARGINAL COST) OF THE FUEL SWITCH FOR A 100 kW GENSETS PLANT UNDER DIFFERENT RD COSTS AND BLENDING RATIOS. AS OBSERVED, RD COST OF <US\$1/KG (US\$1.2/LITRE) WOULD BE REQUIRED FOR A VIABLE COST SHIFT TO RD. **(B)** REPRESENTS THE BREAKDOWNS OF THE ELECTRICITY PRODUCTION COSTS AT VARYING RD PRICES. AS OBSERVED, THE PRIMARY COST DRIVER IS THE RD FUEL PRICE (>90% OF THE ELECTRICITY PRODUCTION COST).

## 5.4. Land Transportation

The end-use application of hydrogen in the land transportation sector is modelled for adopting fuel cell electric-driven buses and trucks and replacing diesel with renewable diesel in existing fleets.

### Total Cost of Ownership

To evaluate the economics of these opportunities, the total cost of ownership (TCO) of the vehicles is evaluated. The TCO represents the cost per distance travelled (US\$/km). The TCO for the alternate fuel was compared against conventional fossil diesel to estimate the marginal premium cost for shifting to cleaner fuel (US\$/km) were calculated, as shown:

$$\text{TCO} \left( \frac{\text{US\$}}{\text{km}} \right) = \frac{\text{CRF} \times \text{CAPEX (US\$)} + \text{OPEX} \left( \frac{\text{US\$}}{\text{yr}} \right)}{\text{Targeted Travel (km)}}$$

$$\text{Cost Premium} \left( \frac{\text{US\$}}{\text{km}} \right) = \text{TCO}_{\text{Diesel}} - \text{TCO}_{\text{H}_2/\text{Derivative}}$$

### H<sub>2</sub> Fuel Cell Electric Vehicles

Below, the marginal cost of replacing fossil diesel vehicles with H<sub>2</sub> fuel cell electric vehicles is estimated. This is done for heavy-duty vehicles such as buses and trucks, given that

FCEVs are likely to be more competitive with battery-electric vehicles in these market sectors. **Table 18** lists the parameters adopted to estimate the TCO of FCEVs and diesel vehicles. **Note:** A sensitivity analysis is conducted to highlight a pathway for cost parity further; the sensitivity parameters are reflected in the brackets in the table.

**TABLE 18. OPERATIONAL PARAMETERS AND EXPENSES OF DIESEL AND FUEL CELL ELECTRIC BUSES AND TRUCKS.**

Parameter	Unit	Diesel Bus	Diesel Truck	FCEV Bus	FCEV Truck
Travel distance	km/day	100 <sup>81</sup>	250 <sup>81</sup>	100 <sup>81</sup> (50 – 1,000)	250 <sup>81</sup> (50 – 1,000)
Operational Days	Days/year	300 <sup>81</sup>			
Ownership period	years	10 <sup>81</sup>			
Purchase cost	US\$	300,000 <sup>81</sup>	250,000 <sup>81</sup>	850,000 <sup>xxxiv</sup> 82	700,000 <sup>xxxv</sup> 83
				(250,000 – 2,000,000)	
Maintenance	US\$/year	20,000 <sup>81</sup>	10,000 <sup>81</sup>	9,000 <sup>84</sup> (1 – 3 times)	9,000 <sup>84</sup> (1 – 3 times)
Insurance	US\$/year	500 <sup>81</sup>	1,500 <sup>81</sup>	500 (500 – 5,000)	1,500
Fuel	L or kg H <sub>2</sub> /100 km	35	37	6 <sup>85</sup> (4 – 20)	9 <sup>86</sup> (4 – 20)
	\$/L or \$/kg of H <sub>2</sub>	1.1 <sup>63</sup>	1.1 <sup>63</sup>	10 (2 – 20)	10 (2 – 20)
WACC	%	5	5	10 (5 – 10)	10 (5 – 10)

**Figure 27** provides an outlook on the economics of shifting from diesel trucks and buses to their FCEV counterparts.

**TCO Estimates:** The TCO estimates (**Figure 27A**) suggest that operating the fuel cell bus and truck will cost US\$5.5/km to US\$2.6/km, relative to the diesel bus and truck cost of ~US\$1.8 – 2.4/km. This would reflect a cost premium of US\$0.8/km to US\$3.1/km for shifting to the fuel cell counterparts.

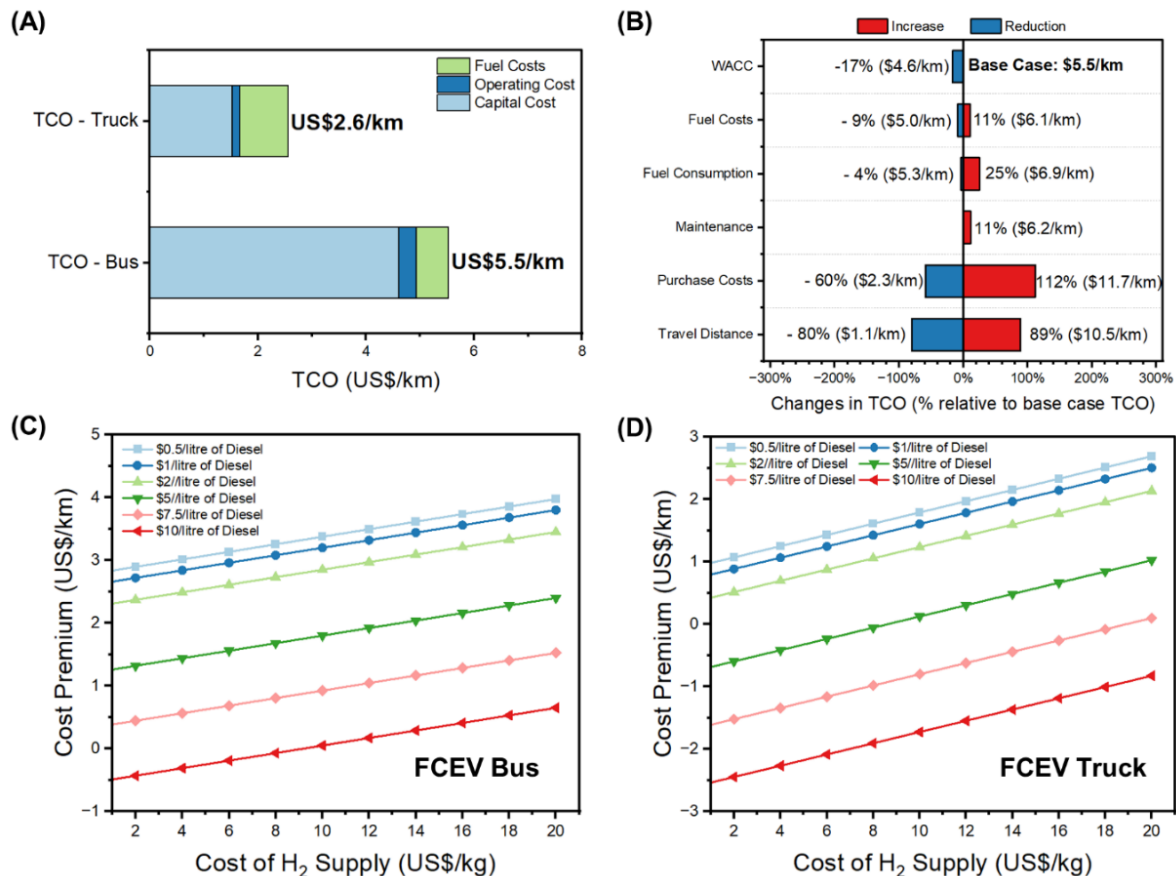
**TCO Sensitivity Analysis:** The sensitivity analysis (**Figure 27B**) shows that the key drivers of the TCO are the cost of purchase and the distance travelled per day. Increasing the distance travelled (10 times the base case), and lower purchase cost (1/3<sup>rd</sup> of the base case) can decrease the TCO by 60% to 80%, respectively. In reverse, an increase in the purchase cost and decreasing the distance travelled will cause the TCO to go up by 90% to 112%, respectively. The cost of fuel and the overall fuel consumption, in comparison, have little impact on the TCO, as decreasing these will cause the TCO to fall by 4% to 9%.

**Cost Premium for Shifting to FCEVs:** To expand on this, **Figure 27C-D** reflects the changes in cost premium for switching from diesel to FCEVs as a function of H<sub>2</sub> and diesel fuel costs. From an FCEV bus perspective, under the current diesel price of US\$1/litre

<sup>xxxiv</sup> The fuel cell bus purchase costs were assumed based on DoE expectations of US\$850,000 that suggest a bus cost of US\$600k with an additional cost of US\$200k for the fuel cell and battery storage and US\$50k for onboard hydrogen storage.

<sup>xxxv</sup> The fuel cell truck purchase costs were assumed based on the costs provided by Nikola Motors that are a US based OEM of FCEV trucks.

(Fiji)<sup>63</sup>, and even the most optimistic H<sub>2</sub> fuel cost of US\$2/kg, the cost of shift would be higher than US\$2.5/km. In comparison to the diesel-operated bus, the FCEV variant will cost US\$75,000/year more or US\$0.75 million more to operate across the lifetime (assuming the bus travels 100 km per 300 days of the year and for ten years). Similarly, for the FCEV truck, the cost of shift will be US\$0.8/km, which would translate to US\$60,000/year or US\$0.6 million more to operate over the lifetime compared to the diesel truck (assuming the FCEV truck travels 250 km per 300 days of the year and ten years). From a hydrogen fuel supply perspective, the H<sub>2</sub> production costs of US\$8-13/kg are estimated, which reflects that the switch to the FCEVs will not be economical in the near term.



**FIGURE 27. ECONOMICS OF H<sub>2</sub> USE FOR LAND MOBILITY APPLICATIONS IN PICTS.** HERE (A) REPRESENTS THE BREAKDOWN OF THE TOTAL COST OF OWNERSHIP FOR OPERATING A FUEL CELL ELECTRIC BUS AND TRUCK. AS OBSERVED, THE COST OF AN FCE BUS IS ~2 TIMES HIGHER THAN THAT OF A CAR. THIS IS DUE TO A HIGHER PER UNIT CAPITAL COST CONTRIBUTION OF THE BUS FOR THE DISTANCE TRAVELLED. (B) REPRESENTS THE SENSITIVITY ANALYSIS OF TCO, WITH THE VEHICLE PURCHASE COST AND ANNUAL DISTANCE TRAVELLED AS THE PRIMARY DRIVER OF THE TCO. MOREOVER, THE ESTIMATED COST PREMIUM (MARGINAL COST) FOR SHIFTING TO (C) FUEL CELL ELECTRIC BUS AND (D) TRUCK AS A FUNCTION OF DIESEL FUEL AND H<sub>2</sub> SUPPLY COSTS. AS OBSERVED, A DIESEL COST OF US\$7.5/LITRE AND AN H<sub>2</sub> FUEL COST OF US\$2/KG WOULD BE REQUIRED FOR THE FCEVs TO BECOME COMPETITIVE WITH DIESEL-OPERATED FLEETS IN THE PICTS.

Nevertheless, we estimate that the anticipated cost reduction in electrolyser and renewable energy costs over the long run might cause the LCOH to decrease to US\$2/kg or below, enabling a more economical shift to FCEVs in the future. In addition, it is essential to note that these TCO estimates do not include the cost of setting up and operating the H<sub>2</sub> refuelling station. Given that H<sub>2</sub> is dispensed as a gas for onboard storage, existing liquid refuelling stations cannot be used. For a heavy-duty refuelling station catered for

buses and trucks, the refuelling station the H<sub>2</sub> would have to be stored and dispensed at high pressures of 700 bars. IEA estimates that a standard 550 kg/day H<sub>2</sub> refuelling station will cost US\$2,350/kg/day to develop. i.e. an equipment cost of US\$1.3 million. Assuming a 10% WACC and an operational lifetime of 30 years with a 10% to 30% utilisation rate, these costs would translate to an additional cost per US\$2–6/kg on top of the H<sub>2</sub> production costs.<sup>87</sup> Therefore, the current production cost of US\$10/kg is pushing the dispensed diesel costs to over US\$14–16/kg, which would need the diesel costs to increase to >US\$7.5/litre for H<sub>2</sub> FCEVs to become viable in the near term. This is a significant disadvantage compared to other biofuels like methanol or renewable diesel that can be used as drop-in replacements in existing liquid refuelling stations. There is also competition from BEVs.

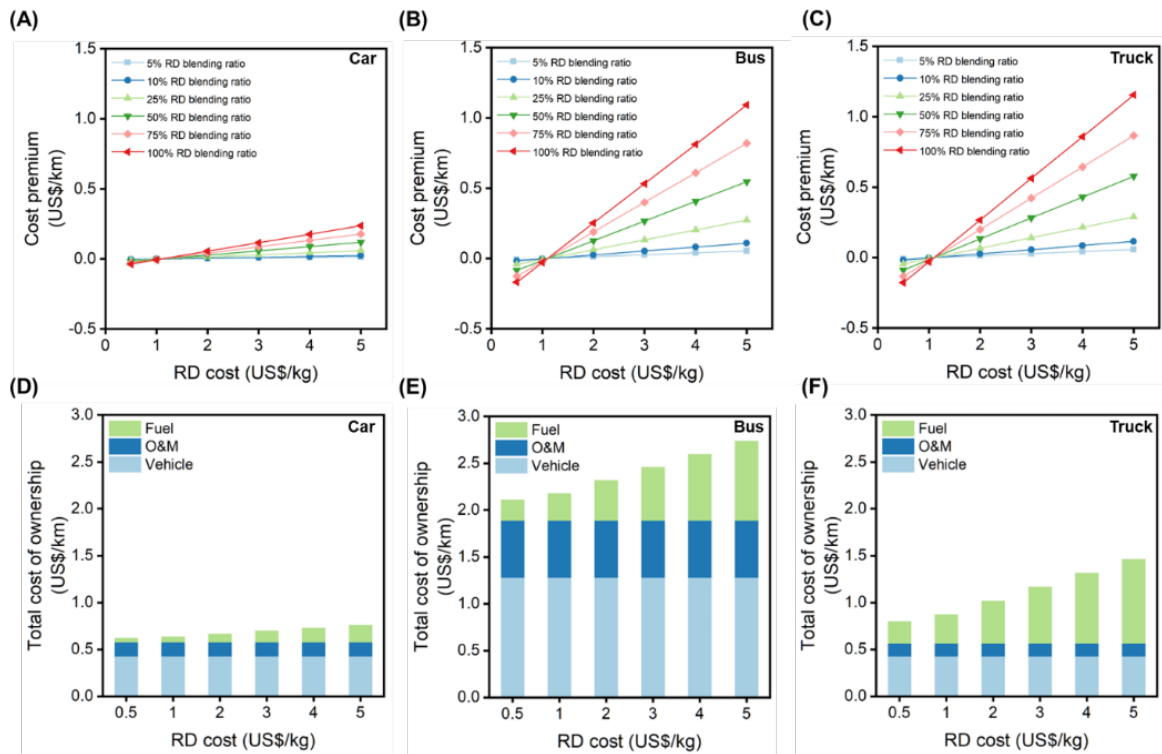
### Renewable Diesel Use for Land Transport

Similarly, the cost of deploying renewable diesel to replace fossil diesel to operate vehicles is estimated. The TCO parameters adopted are summarised in **Table 19**.

**TABLE 19. OPERATIONAL PARAMETERS AND EXPENSES OF DIESEL CARS, BUSES, AND TRUCKS.**

Parameter	Unit	Car	Bus	Truck
Travel distance	km/day	50 <sup>81</sup>	100 <sup>81</sup>	250 <sup>81</sup>
Ownership period	years	10 <sup>81</sup>	10 <sup>81</sup>	10 <sup>81</sup>
Purchase cost	US\$	50,000 <sup>81</sup>	300,000 <sup>81</sup>	250,000 <sup>81</sup>
Maintenance & Service	US\$/year	1,000 <sup>81</sup>	20,000 <sup>81</sup>	10,000 <sup>81</sup>
Insurance	US\$/year	1,500 <sup>81</sup>	500 <sup>81</sup>	1,500 <sup>81</sup>
Fuel	L/100 km	7.6 <sup>88</sup>	35 <sup>88</sup>	37 <sup>88</sup>
	\$/kg	1.1 (fossil diesel) <sup>63</sup>		
Discount	%	7	7	7

**TCO Estimation:** The TCO estimates are shown in **Figure 28**. The TOC provides a way to calculate the costs of owning and operating a vehicle over a period. At the current fossil diesel price of US\$1.1/kg, the TCO values are estimated to be US\$0.64/km for cars, US\$2.19/km for buses, and US\$0.89/km for trucks. The TCO values for different renewable diesel costs and blending ratios are then calculated to evaluate the cost premium for shifting to renewable diesel (**Figure 28A-C**). The TCO breakdowns at a 50% blending ratio are presented in **Figure 28D-F** to reflect the contribution of fuel cost to the TCO under different renewable diesel costs.



**FIGURE 28.** ECONOMICS OF RENEWABLE DIESEL USE FOR LAND MOBILITY APPLICATIONS IN PICTS. HERE, THE COST PREMIUM (MARGINAL COST) OF FUEL SHIFT TO RD IS REPRESENTED FOR A (A) CAR, (B) BUS, AND (C) TRUCK UNDER DIFFERENT RD COSTS AND BLENDING RATIOS. AS OBSERVED, FOR ALL THE VEHICLES, RD FUEL COST OF <US\$1/kg (US\$1.2/LITRE) WOULD BE REQUIRED FOR A VIABLE FUEL SHIFT. MOREOVER, THE BREAKDOWN OF TCO FOR (D) CAR, (E) BUS, AND (F) TRUCK UNDER DIFFERENT RD COSTS AT 50% BLENDING RATIOS ARE REPRESENTED. AS OBSERVED, CARS AND BUSES PROVIDE THE MORE FAVOURABLE OPPORTUNITY FOR A SHIFT TO RD AS THE FUEL COSTS ARE NOT THE PRIMARY DRIVER, COMPARED TO TRUCKS WHERE THE CONTRIBUTION OF FUEL BECOMES DOMINANT AT HIGHER RD COSTS. NOTE: RD = RENEWABLE DIESEL.

### 5.3. Maritime Transport

Renewable diesel, methanol and ammonia offer an alternative fuelling option for maritime applications.

#### Shipping Cost

The unit cost of shipping cost reflected as US\$/(t.km) were estimated for these new fuels and then used to reflect the marginal premium cost for shifting to cleaner fuel, as shown:

$$SC \left( \frac{\text{US\$}}{\text{t.km}} \right) = \frac{CRF \times CAPEX (\text{US\$}) + OPEX \left( \frac{\text{US\$}}{\text{yr}} \right)}{\text{Tonne} \times \text{annual distance travelled}}$$

$$\text{Cost Premium} \left( \frac{\text{US\$}}{\text{km}} \right) = SC_{FO} - SC_{\text{Methanol}}$$

#### Renewable Diesel Operated Vessels

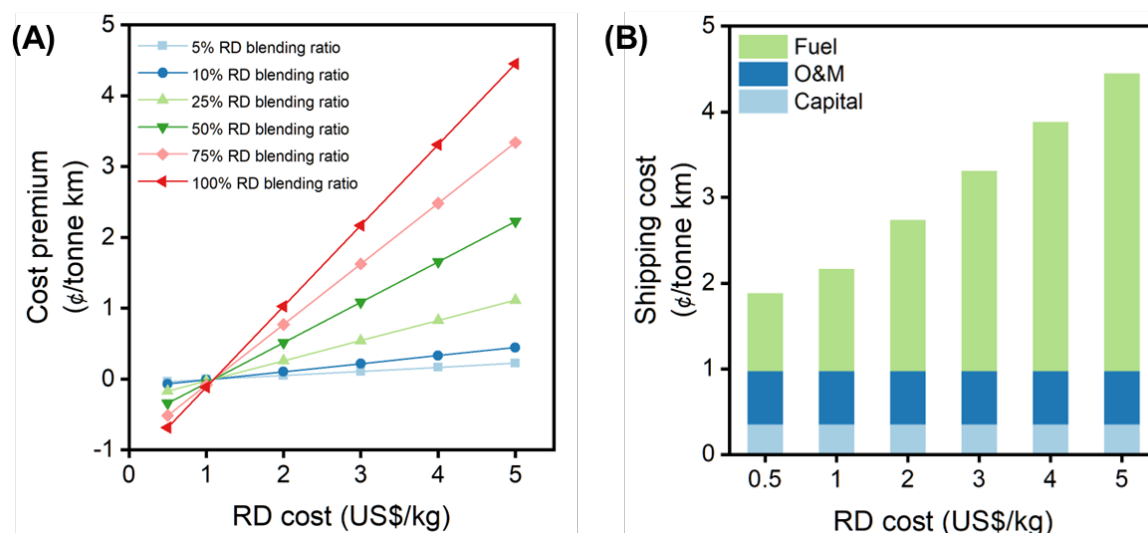
The end-use application of renewable diesel in this sector is modelled for small ships as they offer a drop-in solution without the need to change the engine. The operational parameters and expenses of the vehicles are summarised in **Table 20**.



**TABLE 20.** OPERATIONAL PARAMETERS AND EXPENSES OF GENERAL CARGO SHIPPING.

Parameter	Unit	General Cargo Shipping
Deadweight tonnage	DWT	100
Utilisation rate	%	70
Annual travel distance	km	100,000
Cruise speed	knot	12.6
Vessel purchase	US\$/TEU	23,065 <sup>89</sup>
Fuel	tonnes/day	19 <sup>89</sup>
	US\$/kg	1.1
Maintenance & repairs Insurance	US\$/day	200 <sup>90</sup>
	US\$/day	170 <sup>90</sup>
Crew	US\$/year	50,000
	persons	30
Port charge	US\$/TEU	50
Lifetime	years	25 <sup>91</sup>
Discount rate	%	7

**Shipping Cost Premium:** The estimated shipping cost while operating with renewable diesel is shown in **Figure 29**. At the current fossil diesel price of US\$1/litre, the shipping cost for general cargo is estimated to be US\$2.23/tonne-km. The shipping costs for different renewable diesel costs and blending ratios are then calculated to assess the cost premium for shifting to renewable diesel (**Figure 29A**). The shipping cost breakdowns at a 50% blending ratio are presented in **Figure 29B** to reflect the contribution of fuel cost to the shipping cost under different renewable diesel costs.



**FIGURE 29.** ECONOMICS OF RENEWABLE DIESEL USE FOR MARITIME TRANSPORT. HERE **(A)** REPRESENTS THE COST PREMIUM (MARGINAL COST) OF THE FUEL SHIFT FROM FOSSIL DIESEL TO RD WHEN OPERATING A DIESEL ENGINE-OPERATED SHIP AT DIFFERENT RD COSTS AND BLENDING RATIOS. AS OBSERVED, AN RD FUEL PRICE OF US\$1/KG (US\$1.2/LITRE) WOULD BE NEEDED FOR A VIABLE SHIFT. **(B)** REPRESENTS THE BREAKDOWN OF SHIPPING COSTS UNDER DIFFERENT RD COSTS AT 50% BLENDING RATIOS. AS OBSERVED AT LOW COSTS, THE RD PRICE OF <US\$1/KG CONTRIBUTES A SIMILAR RATIO AS THE CAPITAL AND O&M COST OF THE SHIP, INCREASING TO OVER 90% FOR RD FUEL PRICE OF US\$3/KG. NOTE: RD = RENEWABLE DIESEL.

## Methanol Engine Operated Vessels

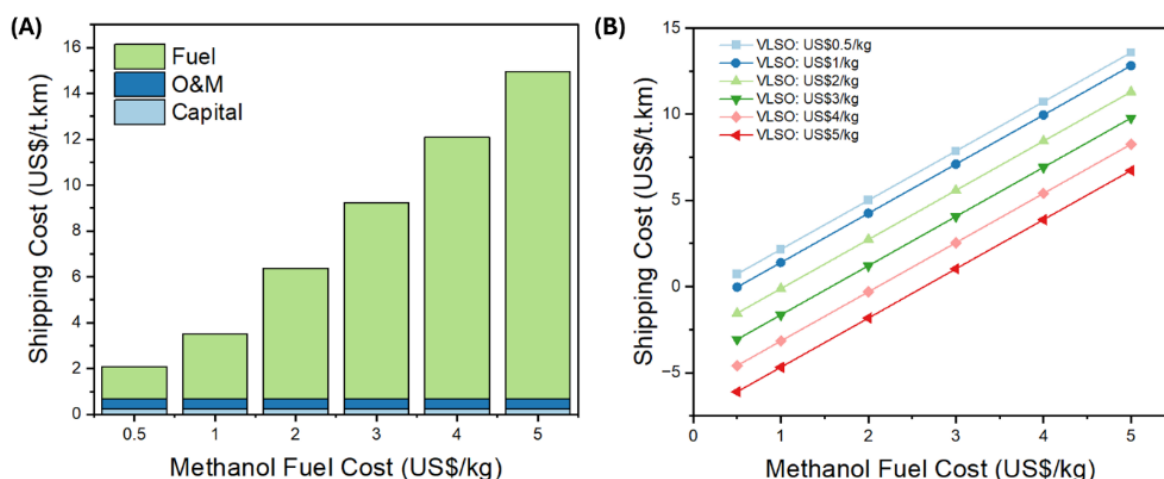
Methanol engines are being developed for maritime applications; at present, they are likely to be installed for large ships such as freight tankers, as highlighted in [Report B](#). Below, the shipping cost for methanol engine-operated cargo ships are evaluated, with the operational parameters and expenses of the vehicles are summarised in [Table 21](#).

**TABLE 21.** OPERATIONAL PARAMETERS AND EXPENSES OF OPERATING GENERAL CARGO SHIP WITH METHANOL AND CONVENTIONAL FOSSIL FUEL.

Parameter	Unit	Fossil Fuel Operated	Methanol Operated
Twenty-foot equivalent unit	TEU	500	500
Deadweight tonnage	DWT	9,000	9,000
Net tonnage	NT	6,000	6,000
Annual travel distance	km	100,000	100,000
Cruise speed	knot	12.6	12.6
Vessel purchase	US\$/TEU	23,065 <sup>89</sup>	31,383 <sup>92</sup>
Fuel	tonnes/day	25	47 <sup>93</sup>
	US\$/kg	0.6 (0.5 – 5)	1 (0.5 – 5)
Maintenance & repairs	US\$/day	200 <sup>90</sup>	200
Insurance	US\$/day	170 <sup>90</sup>	150
Crew	US\$/year/person	50,000	50,000
Crew	persons	30	30
Port charge	US\$/TEU	50	50
WACC	%	7	7
Lifetime	years	25 <sup>91</sup>	25 <sup>91</sup>

**Note:** In this case, the methanol ship would need a specialised engine; the cost of retrofitting the engine in an existing ship is accounted for in the vessel purchase costs.

**Shipping Cost Premium:** The shipping costs for using methanol as a maritime fuel were evaluated, with the results reflected in [Figure 30](#).



**FIGURE 30.** ECONOMICS OF METHANOL USE FOR MARITIME TRANSPORT. HERE (A) REPRESENTS THE SHIPPING COST BREAKDOWN AT DIFFERENT METHANOL SUPPLY COSTS. AS OBSERVED, THE METHANOL FUEL COSTS ARE THE KEY DRIVER OF THE SHIPPING COSTS. (B) REPRESENTS THE PREMIUM COST OF FUEL SHIFT AS OBSERVED; A METHANOL SUPPLY COST OF US\$1/KG AND A VLSO PRICE OF US\$2/KG WOULD BE REQUIRED FOR A VIABLE CHANGE TO METHANOL-POWERED ENGINES FOR HEAVY-DUTY SHIPS.

Under current estimated prices of methanol production in PICTs (US\$0.5 – 5/kg including both e and bio-methanol as shown in **Table 15**), the shipping cost would range between US 2¢/t.km to US 15¢/t.km (**Figure 30A**). A sensitivity analysis is then carried out to evaluate the cost premium for shifting to methanol under different supply costs compared to maritime fuel costs, such as using very low sulphur fuel – VLSO (one of the most used marine fuels) as a reference. **Figure 30B** shows that for ammonia to become competitive (given the current VSLO price of US\$0.6/kg), a methanol cost of <US\$500/tonne would be required.

### Ammonia Engine Operated Vessels

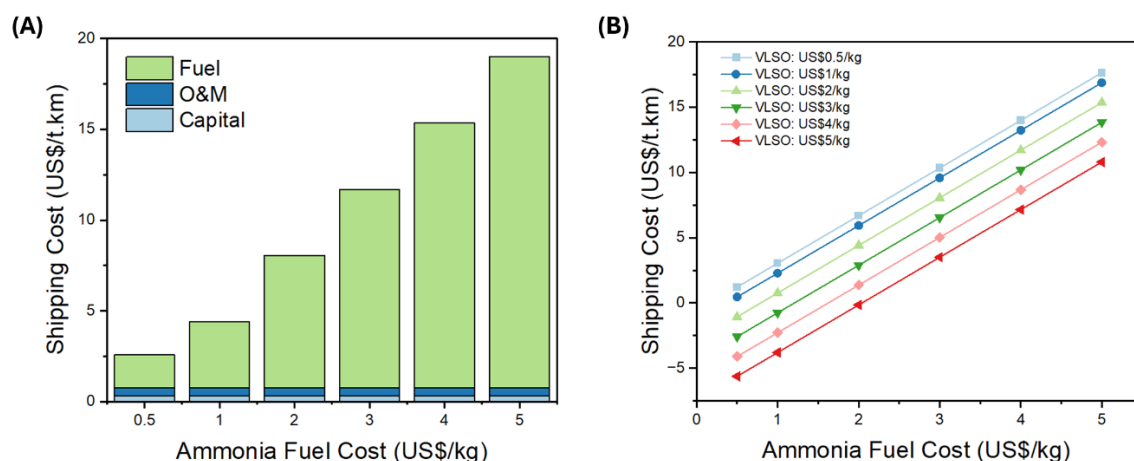
Similarly, the shipping cost for ammonia engine-operated cargo ships is evaluated, with the operational parameters and expenses of the vehicles summarised in **Table 22**.

**TABLE 22. OPERATIONAL PARAMETERS AND EXPENSES OF OPERATING GENERAL CARGO SHIP WITH AMMONIA AND CONVENTIONAL FOSSIL FUEL.**

Parameter	Unit	Fossil Fuel Operated	Methanol Operated
Twenty-foot equivalent unit	TEU	500	500
Deadweight tonnage	DWT	9,000	9,000
Net tonnage	NT	6,000	6,000
Annual travel distance	km	100,000	100,000
Cruise speed	knot	12.6	12.6
Vessel purchase	US\$/TEU	23,065 <sup>89</sup>	31,577 <sup>92</sup>
Fuel	tonnes/day	25 (VLSO) <sup>94</sup>	60 <sup>95</sup>
Fuel Costs	US\$/kg	0.6 (0.5 – 5) <sup>96</sup>	1 (0.5 – 5)
Maintenance & repairs	US\$/day	200 <sup>90</sup>	200 <sup>90</sup>
Insurance	US\$/day	170 <sup>90</sup>	170 <sup>90</sup>
Crew	US\$/year/person	50,000	50,000
	persons	30	30
Port charge	US\$/TEU	50	50
WACC	%	7	7
Lifetime	years	25	25

**Note:** In this case, the ammonia ship would need a specialised engine. The cost of retrofitting the engine in an existing ship is accounted for in the vessel purchase costs.

**Shipping Cost Premium:** The shipping costs for using ammonia as a maritime fuel were evaluated, with the results reflected in **Figure 31**. Under current estimated prices of ammonia production in PICTs (US\$0.5 – 5/kg as shown in **Table 15**), the shipping cost would range between US 2.5 cents/t.km to US 18 cents/t.km (**Figure 31A**). A sensitivity analysis is then carried out to evaluate the cost premium for shifting to ammonia under different supply costs compared to the VSLO costs. **Figure 31B** shows that for ammonia to become competitive (given the current VSLO price of US\$0.6/kg<sup>96</sup>), an ammonia cost of <US\$500/tonne would be required.



**FIGURE 31. ECONOMICS OF AMMONIA USE FOR MARITIME TRANSPORT.** HERE, **(A)** REPRESENTS THE SHIPPING COST BREAKDOWN AT DIFFERENT AMMONIA SUPPLY COSTS. AS OBSERVED, THE AMMONIA FUEL COSTS ARE THE KEY DRIVER OF THE SHIPPING COSTS. **(B)** REPRESENTS THE PREMIUM COST OF FUEL SHIFT. AS OBSERVED, AN AMMONIA SUPPLY COST OF US\$1/KG AND A VLISO PRICE OF US\$2/KG WOULD BE REQUIRED FOR A VIABLE CHANGE TO AMMONIA-POWERED ENGINES FOR HEAVY-DUTY SHIPS.

## 5.6. Aviation Sector

Below, cases for the utilisation of SAF as a drop-in replacement fuel for narrow-body and wide-body passenger aircraft are developed to demonstrate SAF end-use applications for commercial aviation in the Pacific. The following operational parameters and expenses of the aircraft are summarised in **Table 23** are used.

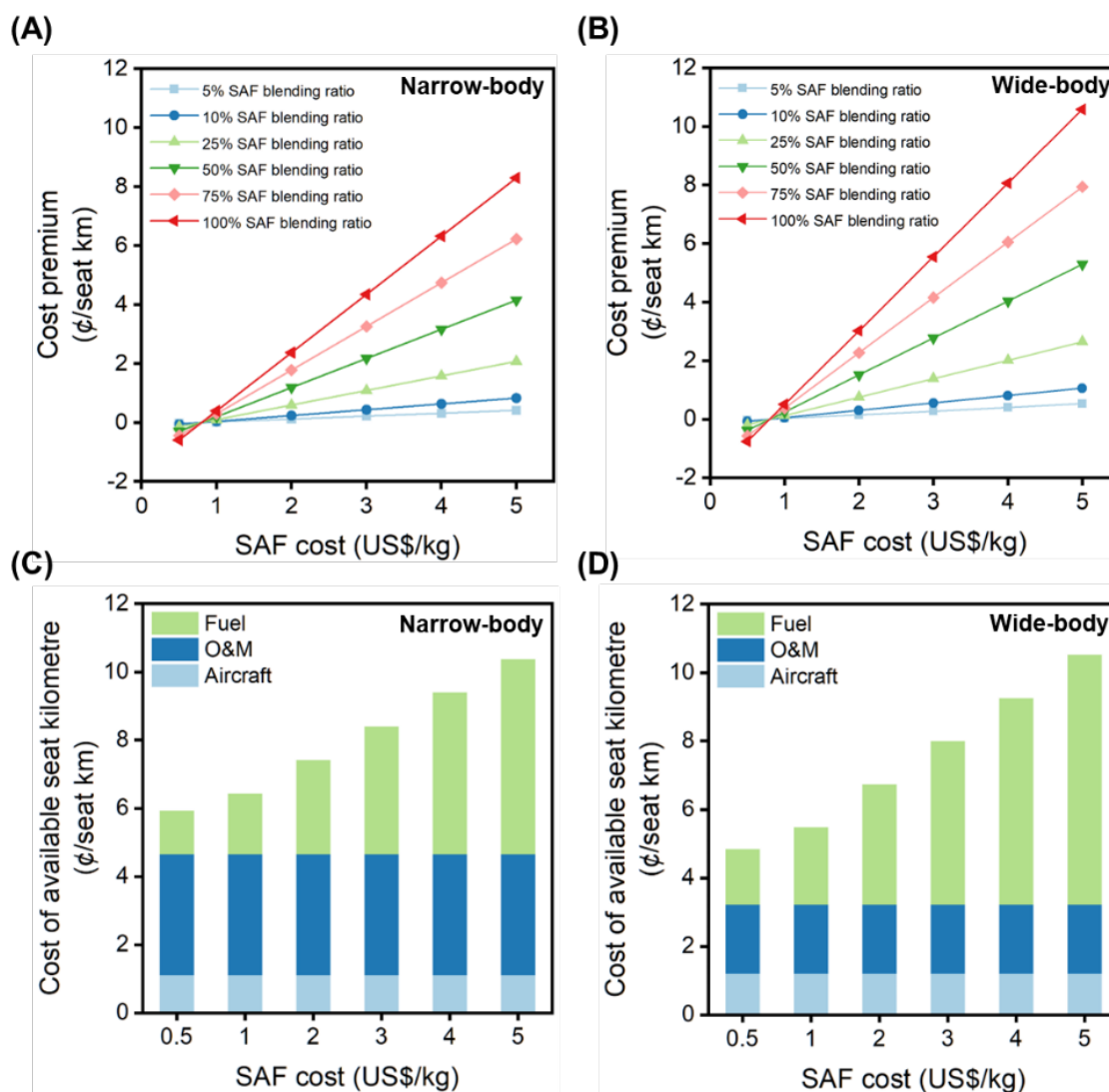
**TABLE 23. OPERATIONAL PARAMETERS AND EXPENSES OF NARROW-BODY AND WIDE-BODY AIRCRAFT PASSENGER CARRIERS.**

Parameter	Unit	Narrow-body aircraft passenger carrier	Wide-body aircraft passenger carrier
Number of seats	seats	180 <sup>97</sup>	250 <sup>98</sup>
Load factor	%	80	80
Flight Distance	km	1,500	4,000
Aircraft cruise speed	km/h	840 <sup>99</sup>	920 <sup>99</sup>
Fuel consumption	L/h	3,200 <sup>100</sup>	5,400
Block hour	h/day	10	14
Annual downtime	days	30	30
Aircraft lease	US\$/month	400,000 <sup>101</sup>	800,000 <sup>102</sup>
Fuel	US\$/kg	0.8 (fossil jet fuel)	0.8 (fossil jet fuel)
Maintenance	US\$/h	700	1,200
Cockpit crew	US\$/h	50	60
	persons	3	3
Cabin crew	US\$/h	20	25
	persons	6	10
Airport	US\$/turn, aircraft	1,000	1,500
	US\$/pax, handling	5	5
Onboard	US\$/pax	5	5

Sales & distribution	US\$/pax	15	15
General & administration	US\$/pax	10	10

### CASK Evaluation:

The estimated cost outlook for shifting the aviation sector to SAF in the PICTs is shown in **Figure 32**.



**FIGURE 32. ECONOMICS OF SAF USE IN PICTs.** HERE, THE COST PREMIUM IS REPRESENTED FOR **(A)** NARROW-BODY PASSENGER AIRCRAFT AND **(B)** WIDE-BODY PASSENGER AIRCRAFT UNDER DIFFERENT SAF COSTS AND BLENDING RATIOS. AS OBSERVED, SAF FUEL COSTS OF US\$1/KG (US\$1.3/LITRE) WOULD BE NEEDED FOR A VIABLE SHIFT. ADDITIONALLY, THE BREAKDOWNS OF CASK FOR **(C)** NARROW-BODY PASSENGER AIRCRAFT AND **(D)** WIDE-BODY PASSENGER AIRCRAFT UNDER DIFFERENT SAF COSTS AT 50% BLENDING RATIOS ARE PROVIDED. AS OBSERVED, FOR SAF SUPPLY COST OF UP TO US\$3/KG (US\$3.9/LITRE), THE COST OF FUEL IS NOT THE MAJOR DRIVER.

At the current fossil jet fuel price of US\$0.8/kg<sup>64</sup>, the CASK values are estimated to be ¢6.23/seat km for short-haul flights on narrow-body aircraft and ¢5.22/seat km for long-haul flights on wide-body aircraft. The CASK values for different SAF costs and blending ratios are then calculated to evaluate the cost premium for shifting to SAF (**Figure 32A-B**). Under a 50% blend, which is a current blending limit set by IATA, an SAF cost of <US\$1/kg would be required for a viable shift.<sup>22</sup> Shifting to higher blends (up to 100%) at

a low SAF cost (US\$1/kg) does not impact the viability. However, at higher costs (SAF cost of >US\$1/kg), deploying these blends would require doubling the premium compared to deploying a 50% blend. The CASK breakdowns at a 50% blending ratio are presented in **Figure 32C-D** and reflect the contribution of fuel cost to the CASK under different SAF prices. As observed, fuel cost is not a significant driver below the SAF cost of US\$4/kg, as fuel consumption has a similar share of the overall costs as the combined cost of the plant and the rest of the O&M costs.

## 5.7. Summary

For evaluating the end-use opportunities, the marginal cost of fuel shift for replacing incumbent fossil fuels with H<sub>2</sub>/derivatives was assessed for the following cases:

- The cost of electricity (US\$/MWh) generated using an H<sub>2</sub> fuel cell and methanol/renewable diesel blending with diesel gensets is levelised.
- Total cost of ownership (US\$/km) of operating a fuel cell vehicle and renewable diesel blending in internal combustion engines.
- Shipping cost (US\$/t.km) of transporting goods using renewable diesel, methanol and ammonia-powered ships.
- Airfare (US\$/seat.km) for operating a flight using SAF as the fuel.

**Table 24** summarises the key findings. As expected, at present, given the expected high supply cost of H<sub>2</sub> and derivatives, shifting to these fuels would incur a premium (higher costs than incumbent fossil fuel use). However, as production costs fall, some of the opportunities for fossil fuel displacements can become viable under the following conditions:

- **Backup Power Generation:** For a viable shift for H<sub>2</sub>-based backup power generation (at least 8 hours of operation a day), the H<sub>2</sub> would have to be supplied below US\$10/kg, whereas renewable diesel (RD) cost of US\$1/kg would be required.
- **Land Transport:** For a viable shift to fuel cell-powered buses and trucks, H<sub>2</sub> fuel costs (including production and dispensing) of US\$2/kg or below would be needed. RD costs of US\$1/kg would be required.
- **Maritime Use:** Similarly, a supply cost of US\$<0.5/kg for ammonia and methanol, whereas RD at a cost <US\$1/kg would be needed for viable maritime use.
- **Aviation Use:** For a viable shift for SAF as an aviation fuel, SAF costs below US\$1/kg would be required.

These costs for methanol, SAF, and RD are possible if generated using the biomass pathway provided. They are produced at scale and for low feedstock costs, as highlighted in **Table 15**. In contrast, shifting to H<sub>2</sub>, ammonia, and methanol generated through the e-pathway in the absence of subsidies/incentives would incur a premium due to their higher production costs.



**TABLE 24. ECONOMIC OUTLOOK OF H<sub>2</sub> AND DERIVATIVE END USE OPPORTUNITIES IN THE PICTs.**

End Use	Marginal Cost of Shift to H <sub>2</sub> and Derivative <sup>xxxvi, xxxvii</sup>									
	H <sub>2</sub>		Ammonia		Methanol		Renewable Diesel		SAF	
Power-Gen	0 – 0.6		-		-		0 – 0.25		-	
Land Transport	0.8 – 2.5		-		-		0 – 0.25		-	
Maritime Use	-		0 - 18		0 - 16		0 - 1		-	
Aviation Use	-		-		-		-		0 - 2	
End Use	Fuel cost needed for parity with incumbent fossil fuel (US\$/kg)									
	H <sub>2</sub>		Ammonia		Methanol		Renewable Diesel		SAF	
	Current Price	Price for Parity	Current Price	Price for Parity	Current Price	Price for Parity	Current Price	Price for Parity	Current Price	Price for Parity
Power-Gen	5 - 19	<13	0.5 – 5.5	-	0.7 – 6.3	-	1.1 – 1.4	1	1.1 – 1.4	1
Land Transport		<2		-		-		1		1
Maritime Use		-		-		-		1		1
Aviation Use		-		-		-		1		1

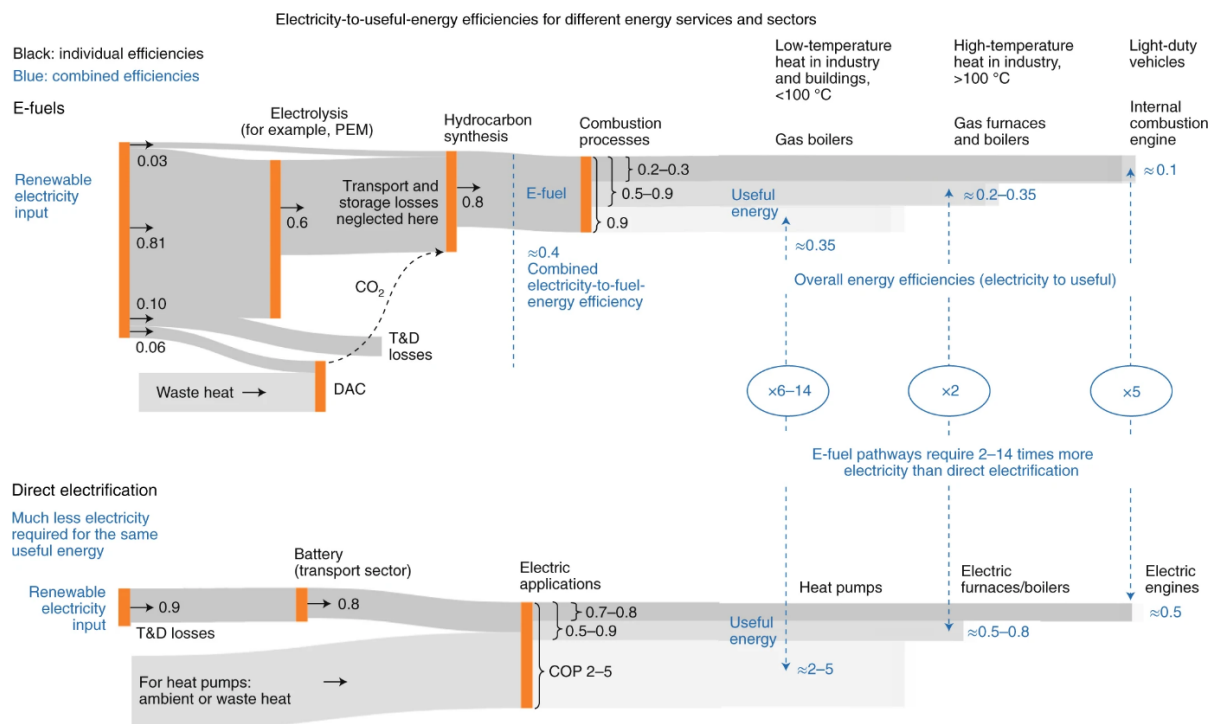
Guide
Not Applicable
Marginal Cost in the range of 0 - 2
Marginal Cost in the range of 0 - 1
Marginal Cost in the range of 0 - 0.5
Marginal Cost in the range of 0 - 0.25

## 5.8. Competition against Direct Renewable Electrification

While the economics of deploying H<sub>2</sub> and derivatives against renewable electrification are not explicitly evaluated herein, it has been acknowledged that they will compete against each other. As highlighted in **Report B**, one of the key advantages is a more straightforward value chain and higher round-trip efficiency. Particularly for e-fuel production, for example, H<sub>2</sub> production via electrolysis requires significant energy (about 25 to 35% losses). These losses are further intensified when H<sub>2</sub> is converted back into electricity or other fuels. Such as, the overall efficiency of direct electrification from renewable sources can exceed 90%, while using H<sub>2</sub> involves the efficiency would be between 25% to 45%, by accounting efficiency of electrolysis (~60% to 80%), storage and transportation (efficiency of 55 to 70%), and fuel cells (~50% efficiency). Offsetting these losses would then require oversizing the equipment (increase in production capacity to accommodate for losses) to achieve comparative outputs to directly electrified equipment. This would require significantly higher upfront cost. As reflected in **Figure 33**, deploying H<sub>2</sub> and derivatives would require 2-14 times more energy than direct electrification.<sup>103</sup> As such, sectors such as light-duty vehicles, low/mid temperature industrial heating (such as steam generation and operations of <400°C), and domestic heating/cooking would be more suited for direct electrification, while H<sub>2</sub> and derivatives would be most competitive in sectors such as aviation and shipping.<sup>103</sup>

<sup>xxxvi</sup> Marginal cost of US\$0/unit or below reflects parity with incumbent fossil fuel. In contrast, a value higher than US\$0/unit represents a premium that would be incurred for shifting to H<sub>2</sub> and derivative compared to the incumbent fossil fuel (cost for fossil fuel operated system subtracted by the H<sub>2</sub>/derivative system).

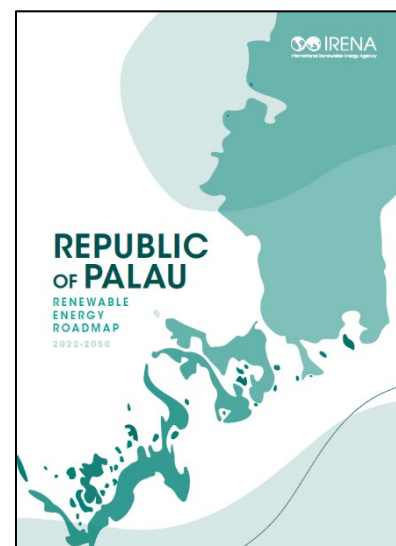
<sup>xxxvii</sup> These marginal costs are estimated based on an average supply cost (including production and distribution to end user) of US\$10/kg of H<sub>2</sub>, ammonia of US\$2/kg and methanol of US\$1-2.3/kg, SAF/RD cost of US\$1-2/kg.



**FIGURE 33. ENERGY CONVERSION EFFICIENCIES OF E-FUELS COMPARED TO DIRECT ELECTRIFICATION FOR DIFFERENT END-USE APPLICATIONS. AS OBSERVED FOR VARIOUS APPLICATIONS SUCH AS POWER PRODUCTION, HEATING AND TRANSPORT SECTORS, E-FUELS WOULD REQUIRE 2-14 TIMES MORE UPFRONT RENEWABLE ELECTRICITY CAPACITY THAN DIRECT ELECTRIFICATION.**

### Learnings from IRENA's Assessments

Moreover, IRENA, as part of the Small Island Developing States (SIDS) Lighthouses Initiative, has conducted a techno-economic study to achieve 100% of Palau's energy needs from renewable energy sources by 2050.<sup>xxxviii</sup> They found that the most cost-effective measures would be to have a large share of renewables (60-80%) with complementing deployment of H<sub>2</sub> (power storage) and battery-based solutions (including electric vehicles). It found that adding electrolysis-based H<sub>2</sub> production to the power system complements a 100% share for renewables through the flexibility provided by electrolyzers, and the large-scale storage of renewable power in the form of H<sub>2</sub> aids in reducing the need for battery storage. The inclusion of EVs is preferably more cost and energy-competitive than H<sub>2</sub>-based refuelling.



Therefore, these highlights further emphasize the emerging consensus that on the overall systems level, direct electrification is likely to be the more competitive and cost-effective solution. While H<sub>2</sub> and derivatives will play a complementary role in hard-to-electrify sectors such as long-term power storage, drop-in fuels (RD for land transport, light duty shipping and on-demand power generation), aviation sector (SAF) and heavy-duty maritime (methanol and ammonia

<sup>xxxviii</sup> <https://www.irena.org/publications/2022/Jun/Republic-of-Palau-Renewable-Energy-Roadmap>

## 6. Conclusion

Overall, the findings from the techno-economic assessment highlight that H<sub>2</sub> and derivatives have a role to play in the context of the PICT's transition to a self-sufficient and renewably driven energy future. There is significant potential for H<sub>2</sub> and derivatives to be produced regionally by leveraging the region's renewable energy and biomass potential. As such, renewable electrolysis-based production of H<sub>2</sub>, ammonia, and methanol is likely to become inherently cost-competitive in the PICTs by 2030, based on the ongoing cost reduction trend of electrolyser and renewable energy costs. The viability of these technologies can then be further supplemented by achieving economies of scale, capital cost financing support and developing regional capacity to supply technology and services. The resource and infrastructure-rich regions of New Caledonia, Fiji, PNG, and Vanuatu can especially emerge as central production and supply hubs for e-fuels in the PICTs. In comparison, biofuel production is potentially already likely to be cost-competitive, provided the facilities can be developed at a large scale. Fiji and PNG are likely to become the more competitive regional hubs as they have high availability and access to the required biomass for cost-competitive production of bio-methanol, renewable diesel, and SAF.

Moreover, under present production costs, end-use opportunities such as on-demand power generation using H<sub>2</sub> fuel cells along with renewable diesel blending for land and small-scale ships are potentially viable. These sectors are critical targets for decarbonisation as part of regional NDC and renewable energy targets. While direct electrification of the energy grid and most land transport (even small-scale and low-distance shipping) is possible and likely to be more economical and straightforward, H<sub>2</sub> and RD provide better solutions for on-demand power generation and distribution across remote and off-grid sites (H<sub>2</sub> and derivatives are more accessible to store and more efficient and easy to transport compared to electricity). Meanwhile, SAF and methanol/ammonia fuels for heavy duty and long haul maritime sector could become feasible with cost and incentives. These are likely to be critical and much-needed opportunities for H<sub>2</sub> and derivatives, given the lack of alternate technologies to replace fossil fuels in the long run. These opportunities have already been considered and realised in the PICTs, with the regional maritime ministers realising the need for alternate H<sub>2</sub> and derivative fuels for the shipping sector.<sup>xxxix</sup> Meanwhile, Fiji Airways has already demonstrated SAF offtake, as highlighted earlier.

Yet, there are significant barriers to entry of H<sub>2</sub> and derivatives at scale, which are highlighted below.

### Economic Challenges

**E-Pathway:** The viability of e-pathways is directly influenced by hydrogen generation costs from electrolysis. At present, and likely for the rest of the current decade, both solar/wind farm and electrolyser technology development costs are likely to remain high, making the e-pathways non-competitive. While similar cost challenges are being experienced globally and have limited the number of projects reaching a financial close, PICTs offer unique challenges such as remoteness and lack of supporting skill sets and infrastructure for project development, which will lead to the actual build costs to be likely

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<sup>xxxix</sup> <https://www.spc.int/updates/news/speeches/2023/05/opening-remarks-of-dr-stuart-minchin-director-general-of-the-pacific>

in the higher end range. Therefore, financing support in the form of grants or cost incentives/offsets, which are becoming commonplace globally, would have to be introduced to support the deployment of these technologies.

**Bio-Pathway:** In comparison, bio-pathways are likely to be more competitive economically. However, this would depend on the technologies to be installed at scale (to take advantage of economies of scale) and the development of a reliable and low-cost supply of biomass feedstocks. Yet, to achieve this, significant upfront investment would be required.

Altogether, if these challenges are overcome, H<sub>2</sub> and derivatives, due to their advantage of being versatile compared to electrification, will enable them to develop niche use cases, particularly for transport applications such as maritime and aviation, which would require significant amounts of energy. There are barriers to entry for electrification technologies, such as technological limitations. Beyond these niche applications, H<sub>2</sub> and derivatives are likely to play a complementary role. Given that the region has made significant progress in growing the share of renewables and biomass use in their energy mix, the deployment of H<sub>2</sub> and derivatives should not remove focus from this growth.

Finally, it is essential to acknowledge that the analysis is based on desktop research and technology stakeholder engagement from a global context. The next stage of the study involves a region-wide engagement with industry, government, and stakeholders through the planned in-country fact-finding workshops. This will lead to critical actions and targets to be set to address the uncertainties and provide a pathway for the development of the PICT's wide H<sub>2</sub> and derivatives value chain, which will be summarised in [Report D](#).

## Infrastructural Challenges

**E-Pathway:** Primarily, the development of e-pathways will face challenges due to global competition and local lack of technology and skill readiness in the region. Generating hydrogen, ammonia, and methanol will require new skills to cater to technologies such as electrolyzers and carbon capture technology such as DAC. Secondly, there is the need for new infrastructure development, especially given that considering emerging certification schemes for these to be certified as renewable and green, dedicated renewable power capacity (potentially off-grid to avoid challenges in fulfilling the spatial and temporal additionality conditions) would have to be built. Moreover, as highlighted in the economics assessment, these powerplants might need to be oversized and additional BESS installed to ensure operation at higher capacity factors. While these measures will eventually reduce the cost per unit of production, making the H<sub>2</sub> and derivatives economically competitive and certified as renewable, they would require significant upfront investment.

Moreover, renewable resources are limited based on their distribution and the land available to leverage them. Therefore, e-fuel production will compete with renewable energy growth in the overall energy mix. While the cost of land is not integrated herein, analysis in [Report B](#) suggested that developing a 100 MW electrolysis facility would require around 3,000 – 10,000 m<sup>2</sup>, i.e. equivalent to one football field. Moreover, given the risks associated with H<sub>2</sub>, an exclusion zone would have to be maintained; for example, for an H<sub>2</sub> refuelling station, an exclusion distance of 125 - 350 m is advised.<sup>104</sup> The footprint of the downstream units also would have to be accounted for. Literature analysis of methanol reactors suggests that 300 m<sup>2</sup> of land would be required for every tonne per hour production capacity.<sup>105</sup> Therefore, given that a 100 tpd production capacity or higher

would be needed for better economics, the methanol reactor plants would take over 30,000 m<sup>2</sup> or 3 hectares (roughly three football fields). Therefore, large-scale facility development would have to be limited to larger islands, and here, it might compete with residential/commercial developments, agricultural land and forest reserves that are critical to the region's ecology. Similarly, H<sub>2</sub> and derivative production will compete for water use, which is a primary feedstock (as producing a kg of H<sub>2</sub> would require 20 litres of water with high purity). For context, if we consider the 1 Mtpa of H<sub>2</sub> produced in the region as estimated earlier to replace fossil fuel use for land transport and electricity production, this will require 0.02 GL/year of ultra-pure water that will put stress on freshwater supply in the region and requiring new water supply such as desalination to be built.

Downstream of production, there is a need for storage and distribution; at present, the Pacific region does not have any gas-ready infrastructure, so new pipelines, distribution networks and storage tanks would have to be developed. Given hydrogen's low density, it would have to be stored under pressure or via liquefaction, both of which are energy and cost-intensive. In comparison, ammonia has its unique challenges. While it has a higher density, it is a toxic chemical that would require new standards and operation procedures to be introduced, which is not available yet in the region. Comparatively, methanol can leverage existing liquid fuel handling infrastructure, and a certain level of blending (potentially up to 30%) can be achieved with diesel. In contrast, a 100% shift to methanol will need changes to infrastructure, including changes to the engine and storage tanks. Methanol is more corrosive, and despite having a similar density to diesel fuels, its energy content is about half, which means twice the storage capacity would have to be developed to achieve the same energy content.

End-use of hydrogen and ammonia will require a significant shift in technology, as new specialised technologies such as hydrogen fuel cells and turbines would have to be introduced, which are still generally globally in their early stage of commercial adoption at scale. Notably, for FCEVs to be deployed, this would require the development of refuelling infrastructure and a social or policy-pushed shift to deploy FCEV fleets. The same applies to ammonia; while it can be potentially used for maritime applications, the current generation of engines is mainly being developed for larger ships.

**Bio-Pathway:** Biofuel offers a more promising outlook, given the region's biomass supply and the ability of renewable diesel and SAF to be deployed as direct drop-in replacements. This is a well-accepted fact for the area, yet integrating a sustainable biomass supply chain with production facilities has been challenging. Secondly, the readiness of the existing infrastructure to handle large volumes of RD and SAF needs to be assessed.

## The Way Forward

Altogether, the findings from these assessments provide a technical and economic pathway for the deployment of an H<sub>2</sub> and derivative value chain in the Pacific and identify key hurdles and challenges that would have to be addressed. The next series of the report (**Report D – A Hydrogen Roadmap for the Pacific**) then builds on these findings to propose a time-bound action plan for developing the potential H<sub>2</sub> value chain.

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