Chapter 5

Hydrogen Economics for Southeast Asian Industries

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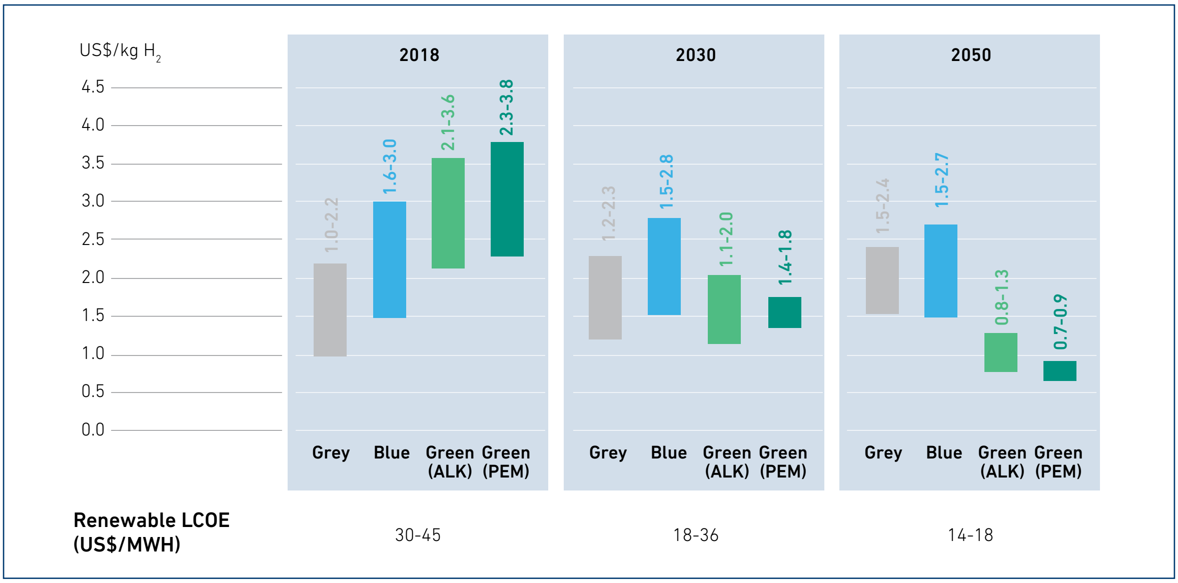
In this chapter, the economics of hydrogen across industries such as ammonia, refineries, methanol, and steel are discussed. Following a summary of current and future hydrogen business models and applications across these sectors, the economics of several production, storage, and transport alternatives are examined. The comparative economic analysis allows formulating potential hydrogen development pathways for these key industries across the relevant ASEAN countries.

1. Global Hydrogen Economics

The majority of hydrogen currently used as feedstock for ammonia and methanol in Southeast Asia is produced via steam methane reforming (SMR). In the region's major refining centres, SMR hydrogen is produced simultaneously with captive hydrogen from reforming and platforming and by products from various refining processes. By contrast, the steel industry still relies mainly on traditional basic oxygen furnace technology. Considering medium- and long-term process optimisation, technology synergies and scale effects, Figure 5.1 demonstrates the current cost advantage of SMR versus blue and green hydrogen alternatives, which is expected to reverse by 2040E–2050E (IESR, 2022b).

Figure 5.1. Hydrogen Cost by Production Type



ALK = alkaline, LCO = levelized cost of electricity, PEM = proton exchange membrane, US$/MWh = US dollars per megawatt hour.

Source: IESR (2022b).

Electrolyser costs are thus expected to decrease due to learning and economy of scale, reaching US$200–US$300 per kW by 2030E. The cost of electricity makes up 30%–60% of hydrogen levelized cost of energy (LCOE). As a result, when the LCOE of solar and wind power decreases to US$20 per MWh by 2030E, the cost of green hydrogen will fall to US$1.1–US$2 per kg by 2030E (IESR, 2022b). By 2050E the cost of green hydrogen could fall below US$1 per kg, with proton exchange membrane (PEM) electrolysis being even cheaper than alkaline electrolyser costs by then.

Other studies reach similar results with regard to the cost competitiveness of various hydrogen production pathways in Southeast Asia. Li and Taghizadeh-Hesary (2020) compare the cost of green hydrogen production and supply versus lithium batteries and pumped hydropower for road transport fuel applications. Similar cost comparison results are observed by Li et al. (2023), who study hydrogen production and supply for power generation via hydrogen fuel cells or mixed combustion in coal or gas power plants. As will be elaborated in section 5.4, these studies combine green hydrogen production technologies with various storage and transport alternatives to derive reasonable estimates of landed, i.e. onsite hydrogen costs. For electrolysis hydrogen, both studies compare the use of selected countries' electricity grids, solar photovoltaic (PV), wind, and geothermal, and assume curtailment to take advantage of the variability in renewable power generation (Chang and Han, 2021). The storage and transport solutions include technologies from gas pipelines, compressed hydrogen trucks and ships, liquid hydrogen shipping, compressed hydrogen trucks and ships, and liquid organic hydride trucks and ships.

2. Global Green Ammonia, Methanol, and Steel Economics

Neuwirth and Fleiter (2020) report on their studies of the potential of and production cost estimates for green hydrogen in the German chemical industry. Assuming electricity prices of EUR0.05/kWh and onsite alkaline electrolysis technology the authors estimate the production costs of hydrogen, ammonia and methanol between 2020, 2030E, and 2050E to reach levels as summarised in Table 5.1.

Table 5.1. Hydrogen, Ammonia, and Methanol Production Costs in Germany

Product	Parameter	Technology	Unit	2020	2030E	2050E
Hydrogen	CAPEX	SMR Electrolysis	EUR/kWh	710 1,100	710 700	710 300
	Production costs	SMR Electrolysis	EUR/kg	2.0 3.4	2.0 3.2	2.0 2.8
Ammonia	CAPEX	SMR Electrolysis	EUR/kW	870	830	750
	Production costs	SMR Electrolysis	EUR/ton	960 1,250	960 1,170	960 1,030
Methanol	CAPEX	Methanol synthesis	EUR/kW	750	730	700
	Production costs	SMR Electrolysis	EUR/ton	1,120 1,340	1,120 1,280	1,120 1,120

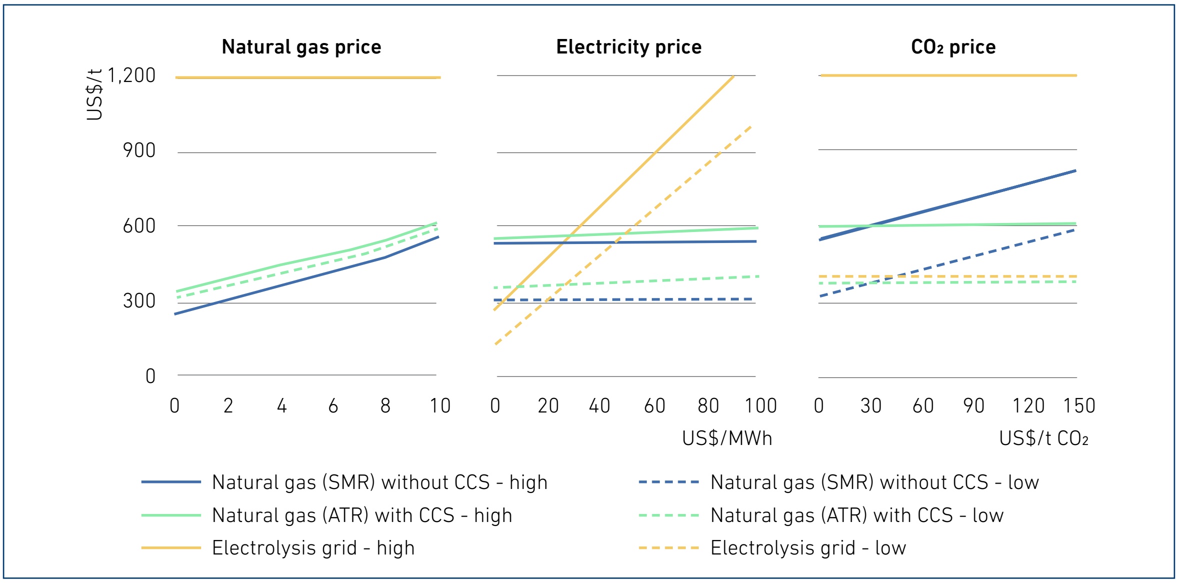
Capex= capital expenditure, E = estimate, kg = kilogramme, kW = kilowatt, SMR = steam methane reforming.

Source: Neuwirth and Fleiter (2020).

Neuwirth and Fleiter (2020) calculate the 2020 production cost of green ammonia in Germany to be around EUR1,250 per ton, higher than SMR-based production costs of about US$960 per ton. They anticipate the cost of green ammonia to decline to US$1,030 per ton in 2050, as economy of scale and learning gain importance.

By comparison, IEA's Ammonia Technology Roadmap (2021b) estimates green and blue hydrogen-based ammonia production costs to depend very much on electricity, i.e. energy costs and technology capital expenditures (CAPEX), as well as on future carbon prices. Figure 5.2 shows that SMR with and without CCS is still cheaper than green hydrogen, even at moderate natural gas prices and low carbon prices.

Figure 5.2. Levelized Cost of Ammonia Production



ATR = autothermal reforming, CCS = carbon capture and storage, SMR = steam methane reforming.

Source: IEA (2021b).

IEA (2021b) observes that the US$600 per ton production cost of blue hydrogen-based ammonia breaks even with SMR hydrogen at a carbon price of about US$30 per ton. Moreover, electrolysis-based ammonia production cost ranges from US$600–US$1,200 per ton, depending on electricity and electrolyser costs. Green hydrogen is clearly more likely to be competitive with SMR when electricity prices are low, natural gas prices are high and electrolyser costs low. Nevertheless, even at low electrolyser costs, electricity costs of lower than US$0.04 per kWh are required to render green hydrogen competitive. Moreover, electrolyser costs must decline by 60% to reach about US$400 per kW electrolyser capacity costs to become comparable to the level of grey hydrogen. By contrast, according to IEA's Global Hydrogen Review (2021a), Hydrogen Council and McKinsey & Company (2022), and IRENA (2020), electrolyser CAPEX estimates still range from about US$1,000 per kW to US$1,750 per kW. Only in 2030E is electrolyser system CAPEX expected to fall to US$230–US$380 per kW. Nevertheless, uncertainties in technology innovation affects the feasibility and timing of the necessary cost reductions (IEA, 2021b).

More recently, Egerer et al. (2023) estimate the cost of ammonia produced via a hybrid solar PV and wind powered electrolyser in Australia and its transport to Germany. The goal is to reconvert the carrier ammonia into hydrogen, the feedstock and fuel of interest. If one strips away the overseas transportation and storage costs, the authors' estimate of the cost of carrier green ammonia sums up to approximately EUR509 per ton (Egerer, et al., 2023). This production cost includes EUR458 per ton of solar PV and wind electricity generation plus a small amount of EUR51 per ton of ammonia synthesis costs.

When it comes to methanol, the study by IRENA and Methanol Institute (2021) estimates current production costs of green methanol to be in the range of US$800–US$1,600 per ton, the upper bound being the case of bioenergy with CCS, or up to US$1,200–US$2,400 per ton in case of CO_2 from direct air capture. Table 5.2 depicts selected production cost estimates fort green methanol based on the choice of renewable power for electrolysis, the choice of carbon to be captured and capacities.

Table 5.2. Selected Studies on Methanol Production Cost by Carbon and Electricity Sources

Carbon source	Electricity source	Electricity US$/kWh	Carbon cost US$/ton	Capacity TPA	CAPEX US$/TPA	OPEX US$/ton	Carbon cost US$/ton
Flue gas	Renewable energy	0.01–0.06	44	1.8 million	1,385–2,770		430–910
CPP flue gas	Grid/renewable energy	0.11–0.13	0	440,000	1,260	740	805
CPP flue gas	Grid/renewable energy	0.044	43	110,000			645
Purchased	Grid	0.024-0.073	59	100,000	1,340		365–826
Flue gas	Renewable energy	0.03		100,000	620	880	810–1,190
Flue gas	Grid			4,000-50,000	1,670–2,780		555–780

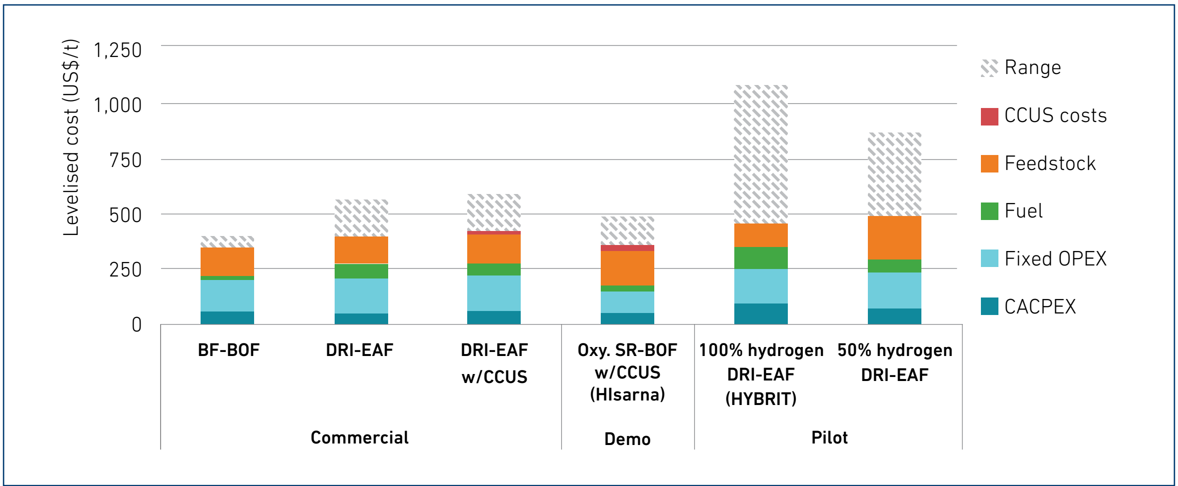
CAPEX = capital expenditure, CPP = coal-fired power plant, kWh = kilowatt per hour, OPEX = operating expenses, TPA = tons per annum.

Source: Adapted from Table 21 in IRENA and Methanol Institute (2021), p.77.

The studies listed in Table 5.2 estimate grid-electricity-based methanol production costs in the range of US$830 per ton, whilst the corresponding production costs for green methanol vary around US$650–US$1,190 per ton. Only the largest 1.8 million tons green methanol plant is estimated to come close to the grid-electricity-based costs. One thus observes that currently the main barrier to green methanol is its higher cost compared to SMR. The IRENA and Methanol Institute study (2021) anticipates decreasing renewable power prices, with green methanol production costs reaching US$250–US$630 per ton by 2050. Noteworthy are also methanol production cost estimates of around US$300–US$1,300 per ton (IEA, 2019).

Not unlike ammonia and methanol, IRENA (2022) estimates that investment and operating costs for DRI steelmaking are 30%–50% higher compared to the traditional SMR route. Particularly the electricity costs will be the key factor determining the future competitiveness of green hydrogen-based DRI. Early estimates were also made by IEA's *The Future of Hydrogen* (IEA, 2019), as can be seen in Figure 5.3, where steel production costs for 50%–100% DRI–EAF reach almost double the hitherto SMR-based, even including CCUS.

Figure 5.3. Estimated Costs of Steel (2018)



Notes: Oxy. SR-BOF = oxygen-rich-smelt reduction. CCUS costs includes the costs of capturing, transporting and storing CO_2. Range refers to the range of total levelised costs across regions, with the lower end of the range disaggregated for each technology. An availability factor of 95% is applied to all equipment and an 8% discount rate is used throughout. It is assumed that the electrolysis route is supplied with 100% renewable electricity. Natural gas-based and 100% hydrogen-based DRI-EAF considers 95% DRI charge to the EAF. More information on the assumptions is available at www.iea.org/hydrogen2019.

BF–BOF= blast furnace–basic oxygen furnace, CAPEX = capital expenditure, CCUS = carbon capture utilisation and storage, DRI–EAF = direct reduced iron–electric arc furnace, OPEX = operating expenses, Oxy. SR–BOF = oxygen-rich smelt reduction.

Source: IEA (2019).

3. Green Hydrogen Transition in Southeast Asia

According to IEA (2021a) up to 850 GW of aggregate renewable electricity capacity is required to produce the world's demand for 80 MTPA green hydrogen by 2050. The hydrogen supply required to feed a midsize 400 KTPA ammonia or 600 KTPA methanol plant ranges from approximately 75 to 85 KTPA. Southeast Asia's largest refineries in Indonesia, Thailand, and Singapore produce approximately 30–70 KTPA of hydrogen, net of their own captive hydrogen from reforming and platforming processes, hitherto supplied by their own captive SMR. We shall show below that to supply these industrial facilities requires about 1,000–2,200 megawatts (MW) single-site, dedicated peak solar PV generation capacity, and up to 700–1,500 MW of electrolyser capacity.

In the Pacific region Australia, China, and the Republic of Korea are currently planning GW-scale single site electrolyser facilities. To date not sufficiently large single-site solar PV, wind, or geothermal electricity generation capacity exist in Southeast Asia. Amongst the announced GW-scale solar PV projects in the region are the Singapore's Sunseap's plans for up to 7 GW capacity around the Indonesian Riau Islands, which include a 2.2 GW floating solar PV project in Batam Island, Australia's ReNu, and Anantara's 3.5 GW project in Riau. Li et al. (2023) quotes the ASEAN Centre for Energy's (ACE, 2020a) 6th ASEAN outlook for renewable electricity generation capacity in the region as summarised in Table 5.3. Thus, significant production, storage, and transport capacity expansion and investments are required.

Table 5.3. Current and Projected Installed Renewable Capacity in ASEAN

Renewable Energy (GW)	2020	2030	2040
Hydro	59.4	81	132
Solar	22.9	31	56
Wind	2.7	7	14
Geothermal	4.1	10	17
Biomass, biogas, waste	6.4	14	23

GW = gigawatt.

Sources: Li et al. (2023) and ACE (2020a).

A transition towards decarbonised hydrogen in industry can be expected to follow a path of staggered blue and green production and infrastructure development. Initially, the more incremental increase in CAPEX and operating costs (OPEX) of introducing CCS technology limits the loss in competitiveness and moderates any fiscal support necessary to incentivise and support the large industrial users and gas merchants. Fossil fuel companies are anticipated to favour the blue hydrogen route, at least in the near term, as we shall discuss in the next chapter. By contrast, the development of green hydrogen production and infrastructure projects will be much costlier and will require significant participation of the electricity sector, as the required power generation capacities will be larger than many solar PV, wind, geothermal, and other renewable power projects hitherto built or planned, even in industrialised Europe and North America. Therefore, whilst government and industry are working on multiple CCS projects across the region, plans must be made to initiate and implement several flagship green hydrogen projects to gain economy of scale and critical mass in green hydrogen production, storage and transport infrastructure, to help kickstart the green transition for all major hydrogen-consuming sectors.

Beyond replacing grey with blue and green hydrogen for the traditional industrial feedstock applications, the ERIA–APS and ERIA–Likely scenarios introduce the utilisation of green hydrogen via green ammonia as energy carrier for storage and transport as well as complementary fuel for coal and natural gas combined cycle power generation. Moreover, in future decarbonisation scenarios, methanol can be used a feedstock for e-fuels, to replace traditional higher emission diesel and gasoline across road transport applications.

4. Economics of Hydrogen in ASEAN

Several studies have analysed potential green hydrogen production, and storage and transport costs in Southeast Asia. The most important cost component is the renewable electricity cost. The solar PV electricity prices that Li and Taghizadeh-Hesary (2020) assume a range from US$0.04 per kWh in Indonesia and Malaysia, US$0.038 per kWh in Thailand, and US$0.041 per kWh in Viet Nam. These electricity costs contrast to Li et al.'s (2023) higher estimated solar PV electricity prices of US$0.165 per kWh in Indonesia, US$0.108 per kWh in Malaysia, US$0.145 per kWh in Thailand, and US$0.092 per kWh in Viet Nam (Table 5.4).

Table 5.4. Cost of Electricity (2020 US$)

Country	Grid Electric-ity (US$/ kWh)	Solar PV (US$/ kWh)	Wind (US$/ kWh)	Hydro-power (US$/ kWh)	Woody Biomass (US$/kg)	Gasoline (US$/ litre)	Diesel (US$/ litre)	Natural Gas (US$/ MMBtu)	Coal (US$/kg)[c]
Brunei Darussalam	0.069	0.118	NA	NA	NA	1.44	1.21	8.3	N.A.
Cambodia	0.202	0.087	0.147	0.046	NA	0.87	0.64	10.7	0.091
Indonesia	0.063	0.165	0.146	0.046	0.042	0.65	0.7	5.6	0.094
Lao PDR	0.124	0.111	0.186	0.046	NA	0.94	0.79	8.3	0.091
Malaysia	0.11	0.108	0.135	0.046	0.035	0.39	0.42	8.2	0.103
Myanmar	0.125	0.079	0.111	0.046	NA	0.53	0.46	8.3	N.A.
Philippines	0.12	0.117	0.128	0.046	0.058	0.99	0.69	10.7	0.091
Singapore	0.156	0.123	N.A.	N.A.	0.042	1.44	1.21	8.6	N.A.
Thailand	0.087	0.085	0.145	0.046	0.042	0.98	0.66	10.7	0.091
Viet Nam	0.101	0.087	0.092	0.046	0.020	0.64	0.47	8.3	0.102

g = kilogramme, kWh= kilowatt hour, MMBtu = metric million British thermal unit, NA = not available.

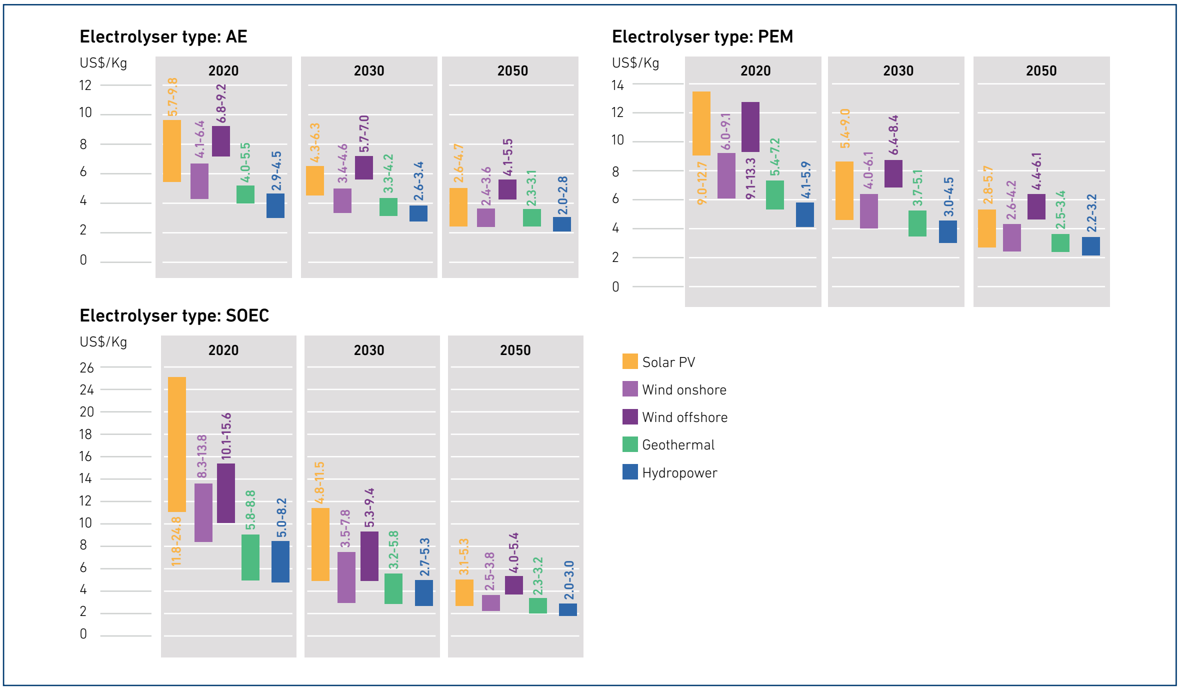
Source: Adopted from Table 6 of Li et al. (2022), p.7.

According to Li et al. (2023) regional grid and wind power prices are higher than solar PV except in Indonesia, where grid prices are subsidised. By contrast, hydropower and woody biomass prices are generally lower. Additionally, the Institute for Essential Services Reform (IESR) (2022b) uses Ministry of Energy and Mineral Resources (MEMR) data to estimate renewable electricity costs in Indonesia of US$0.07–US$0.16 per kWh (for onshore wind), US$0.06–US$0.10 per kWh (large scale solar PV), US$0.05–US$0.09 per kWh (geothermal) and US$0.05–US$0.11 per kWh (biomass). We thus estimate the resulting costs of green hydrogen in Southeast Asia in three ways:

4.1. IESR (2022b) and IEA (2019)

IESR (2022b) combines MEMR electricity costs with IEA's (2019) electrolyser cost, efficiency, and stack lifetime assumptions to compare green hydrogen production costs in Indonesia for the three different types of electrolysis technologies (Figure 5.4).

Figure 5.4 Green Hydrogen Production Estimates



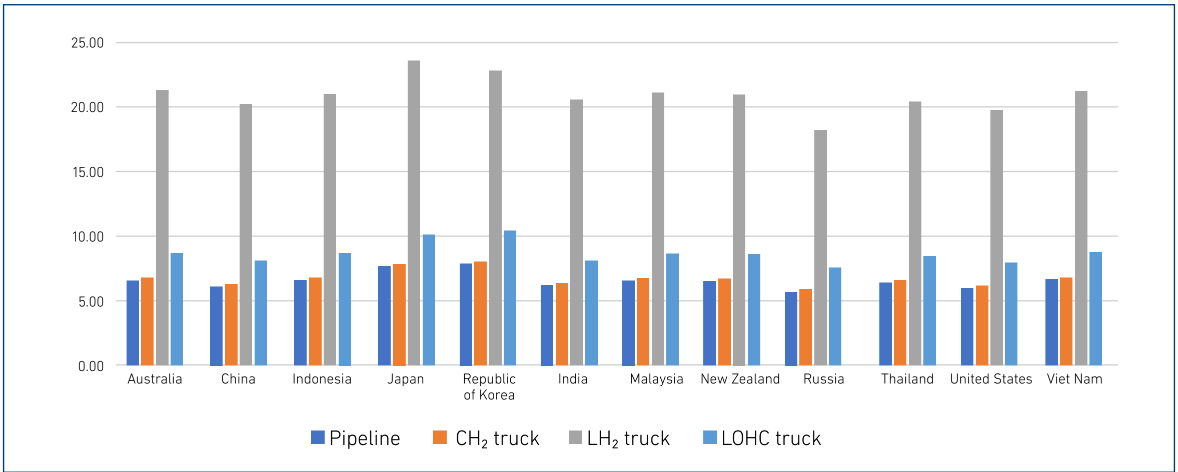
AE = alkaline electrolysis, PEM = proton exchange membrane, PV = photovoltaic, SOEC = solid oxide electrolyser cell.
Source: IESR (2022b).

IESR (2022b) assumes solar PV electricity costs of US$60–US$100 per MWh. The authors calculate the production cost of solar PV-based green hydrogen and expect costs to decrease to US$2.6–US$4.7 per kg by 2050E for alkaline, US$2.8–US$5.7 per kg for PEM respectively US$3.1–US$5.3 per kg for solid oxide electrolyser cell electrolysis. The lower cost of geothermal and location-constrained hydropower reduces these costs to about US$2.0–US$3.2 per kg by 2050E.

4.2. Li and Taghizadeh-Hesary (2020)

Li and Taghizadeh-Hesary (2020) assume multiple stacks of 1,000 MW solar PV, a 25% curtailment rate of annual generation out of 1,752,000 MWh of power, alkaline vs. PEM electrolyser CAPEX of US$1,102 per kW respectively 1,808 per kW capacity and OPEX of about 4.7% of CAPEX, pipeline CAPEX of US$400,000 per kilometre and corresponding OPEX of 8%, various storage, and transport costs ranging from short and medium distance trucking to long distance regional shipping of about 2,000 kilometres. Assuming alkaline electrolysis technology they calculate the cost of producing, 7-day storing, and delivering green hydrogen to a refuelling station 100 kilometres away (Figure 5.5).

Figure 5.5 Cost of Green Hydrogen at Refuelling Station at 500 km Trucking Distance (US$/kg)



CH_2 = compressed hydrogen, kg = kilogramme, km = kilometre, LH_2 = liquid hydrogen, LOHC = liquid organic hydrogen carrier
Source: Li and Taghizadeh-Hesary (2020).

Clearly, apart from the extremely expensive cost of transporting compressed hydrogen, their study indicates prices of US$6–US$10 per kg of hydrogen at delivery point.

4.3. ERIA (2023)

For sufficiently sizeable industrial facilities it would be beneficial to locate a large-scale renewable energy and green hydrogen production facility inside-battery-limit or directly adjacent to a refinery, ammonia, methanol, or steel facility. A synthesis of selected assumptions from third parties, i.e., Li and Taghizadeh-Hesary (2020), IESR (2022), Chang and Han (2021) and Li et al. (2023) solar PV, electricity, and electrolyser cost studies is made. It should be noted that this study itself does not explicitly analyse the economics of the solar PV facilities. By locating the solar PV and electrolyser facilities next to the industrial plant, it is assumed that there is no major pipeline or trucking transport CAPEX and OPEX, storage and refuelling or downstream power generation costs. This helps us estimate the effective costs of delivering green hydrogen at the target industrial site.

The starting point is a 2,000 MW solar PV electricity generation facility with a capacity factor of 20%. We consider a multi-stack electrolyser of 1,500–2,000 MW, closer to the combined capacity of 1,330 MW typically required for a 2,000 MW solar PV farm. A 16-year effective electrolyser lifetime, energy consumption rates of 3.98 kWh per Nm^3 hydrogen for alkaline electrolysers, and 3.48 kWh per Nm3 for PEM electrolysers and a system utilisation rate of 80% are utilised. Additionally, capital costs, i.e. discount rates of 8% are used across Southeast Asia. The electrolyser and electricity cost estimates are summarised in Table 5.5:

Table 5.5. Onsite Solar PV-based Green Hydrogen Production Assumptions

Southeast Asia	Electrolyser CAPEX (US$/kW)	Electrolyser Annual OPEX (% CAPEX)	Electrolyser Energy Consumption (kWh/Nm^3)	Electricity
Today	Alkaline 1,102	4.7%	3.98	Li et al. (2023)
	PEM 1,808	4.6%	3.48	
2030E	Alkaline 400	4.7%	3.98	0.06–0.10
	PEM 650	4.6%	3.48	
2050E	Alkaline 200	4.7%	3.98	0.04–0.08
	PEM 300	4.6%	3.48	

CAPEX = capital expenditure, E =estimate, kW = kilowatt, kWh= kilowatt hour, Nm3 = normal cubic metre, OPEX = operating expense, PEM = proton exchange membrane.

Source: Authors based on the above studies.

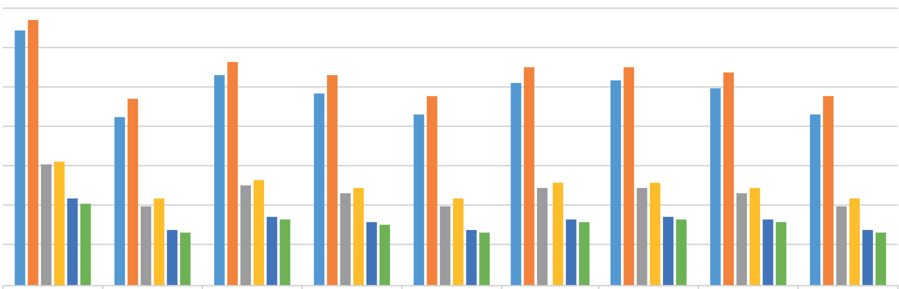
Starting with Li and Taghizadeh-Hesary's (2020) electrolyser CAPEX for a project today, roughly 20%–30% regional cost buffers are added to IEA's (2019) and IESR's (2022b) future 2030E and 2050E CAPEX estimates. Thus CAPEX estimates of approximately US$500 per kW for alkaline and US$800 per kW for PEM electrolysers by 2030E, and about US$300 per kW respectively US$400 per kW by 2050E, are calculated. Electrolyser CAPEX, the corresponding OPEX as well as solar PV electricity costs decline further beyond 2030E towards 2050E. As per Chang and Han (2021) and others, running an electrolyser at high load factors, i.e. high full load hours decreases the annualised cost of electrolyser CAPEX, thus lowering the unit production cost of hydrogen. These assumptions lead to a 1,330 MW alkaline electrolyser producing about 63,300 tons per annum of green hydrogen and consuming about 55.4 kWh electricity for every kg of hydrogen, and a PEM electrolyser producing about 72,400 TPA of green hydrogen and consuming 48.4 kWh per kg green hydrogen.

Between 700–1,500 MW of electrolyser capacity are required to serve a medium or large-scale ammonia, methanol or refinery facility. This necessitates electrolyser investment costs of almost US$0.9–US$2.7 billion (at today's CAPEX levels), US$0.3–US$1.0 billion (2030E), or US$0.2–US$0.5 billion (2050E) for the electrolyser facility alone, the lower and upper ranges corresponding to alkaline versus PEM electrolysis systems, respectively. This assumes the availability of 1 to 2 GW of solar PV or other equally large renewable electricity generation capacities in the vicinity of the electrolyser and target industrial facilities, which may cost another US$0.6–US$1.2 billion of upfront CAPEX plus associated OPEX.

Importantly, current renewable solar PV-based electricity input prices are assumed to follow Li et al. (2023). For 2030E, by contrast, IESR's (2022b) estimated prices in Indonesia of US$0.06–US$0.10 per kWh are used, combined with proportional reductions for other ASEAN countries in line with to Li et al.'s (2023) estimates. Finally, this study estimates price reductions towards US$0.04–US$0.08 per kWh electricity by 2050E in Indonesia, whilst assuming region-wide price reductions proportional to Li et al.'s (2023) country-by-country variations.

The resulting hydrogen production and onsite delivery costs are shown in Figure 5.6.

Figure 5.6 Hydrogen Production Cost (US$/kg): Onsite Solar PV Electrolyser



	Indonesia	Thailand	Singapore	Malaysia	Viet Nam	Philippines	Brunei	Myanmar	Cambodia
Alkaline (today)	12.85	8.42	10.52	9.69	8.53	10.19	10.24	9.86	8.53
PEM (today)	13.28	9.41	11.25	10.52	9.50	10.96	11.00	10.67	9.50
Alkaline (2030E)	6.11	3.97	4.99	4.58	4.02	4.82	4.85	4.66	4.02
PEM (2030E)	6.21	4.34	5.23	4.88	4,38	5.09	5.11	4.95	4.38
Alkaline (2050E)	4.33	2.72	3.49	3.18	2.76	3.37	3.39	3.25	2.76
PEM (2050E)	4.07	2.67	3.34	3.07	2.70	3.23	3.25	3.12	2.70

Alkaline (today) PEM (today) Alkaline (2030E) PEM (2030E) Alkaline (2050E) PEM (2050E)

PEM = Proton Exchange Membrane.

Sources: ERIA calculations based on IEA (2019), Li and Taghizadeh-Hesary (2020), Chang and Han (2021), Li et al. (2023).

Whilst current costs of producing green hydrogen in the ASEAN region reach as high as US$8–13 per kg, levelized production costs of US$4.0–US$6.2 per kg and US$2.7–US$4.3 per kg are anticipated by 2030E and 2050E, respectively. As electrolyser and renewable energy capacity and operating costs decrease, we thus anticipate green hydrogen to become more competitive towards 2030E and especially towards 2050E. Note that, if the PV solar capacity factor is reduced from 20% to 15%, the levelized green hydrogen production costs increase to US$10–US$14 per kg at today's cost levels, US$4.5–US$7.0 per kg by 2030E, and US$3.1–US$4.7 per kg by 2050E.

It should also be noted that the above cost estimates exclude the cost of short-distance hydrogen pipeline transport and storage systems, which could mean an additional cost of US$500,000 per km of pipeline CAPEX plus associated OPEX (Li and Taghizadeh-Hesary, 2020). Of course, optimal future transportation options must be studied in greater detail, by comparing hydrogen transport routes via pipelines, compressed or liquid hydrogen trucks, or liquid organic hydrides. Furthermore, a 1 GW single-side solar PV facility would require approximately 10 square kilometres of land space. This represents land area the size of 1,400 football fields, which may not be available in the vicinity of the typical refinery, ammonia, methanol, and steel facilities. Any distance between the solar farm and electrolyser site would require additional power transmission lines and contracting with the responsible power transmission and grip operators.

Clearly some combination of public sector co-financing, subsidies, or tax breaks, optimal carbon prices, and collaboration with multiple regulators, public and private companies are necessary to plan and implement the production of green hydrogen in the near term. As a consequence, the feasibility of implementing a green hydrogen transition in ASEAN industries hinges on an analysis of the political economy of hydrogen in the region.

Last but not least, per Figure 5.1 based on IESR (2022b) the cost of CCUS is expected to increase the production cost of grey hydrogen by only US$0.6–US$0.8 per kg today, US$0.3–US$0.5 per kg by 2030E and only US$0.1–US$0.3 per kg by 2050E. As a result, blue hydrogen is expected to play a significant interim role throughout the transition towards green hydrogen, i.e. until green hydrogen technology can become truly competitive in the ASEAN region.